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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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In re: Progress Energy Florida, Inc.'s Petition for Approval of Southeast Supply Header long-term fuel transportation contracts.	))))	Docket No. 060793-EI Filed: January 19, 2007

PROGRESS ENERGY FLORIDA, INC.'S
NOTICE OF SERVICE OF
<u>RESPONSES TO STAFF'S FIRST DATA REQUEST</u>

Progress Energy Florida, Inc. ("PEF"), by and through its undersigned counsel, hereby provides notice of service of its Responses to Staff's First Data Request, by hand delivery on Lisa C. Bennett, Esq., Florida Public Service Commission, Office of General Counsel, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850. A copy of PEF's Responses to Staff's First Data Request with confidential portions redacted is filed herewith with the Commission Clerk.

Respectfully submitted this 19th day of January, 2007.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was furnished by Hand Delivery to the following this 19th day of January, 2007:

Lisa C. Bennett, Esq.
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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January 19, 2007

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Lisa C. Bennett, Esq.
Florida Public Service Commission
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2540 Shumard Oak Boulevard
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Re: Docket No. 060793-EI - Petition for approval of long-term fuel transportation contracts with Duke Energy Southeast Supply Header, LLC and CenterPoint Energy Southeastern Pipelines Holding, L.L.C. ("SESH Pipeline Contracts"), by Progress Energy Florida, Inc.

Dear Ms. Bennett:

By this letter, Progress Energy Florida, Inc. ("PEF") hereby provides its Responses to the Commission Staff's First Data Request:

1. Why does PEF seek approval of its long-term fuel supply and transportation contracts with the Southeast Supply Header, LLC (SESH), as opposed to only seeking Commission approval of the SESH project's costs as prudent and reasonable for fuel clause cost recovery purposes? In responding to this question, please include responses to the following questions:

A.) If the Commission only approves PEF's SESH project for cost recovery purposes and does not approve the long-term fuel supply and transportation contracts, will PEF continue with the SESH project? Please explain.

PEF's Response: PEF will have to seriously weigh the risks associated with going forward with this project in the absence of Florida Public Service Commission ("PSC" or "Commission") approval. Simply finding that the costs are of a nature recoverable through the fuel clause and not addressing the prudence of entering into a long-term contract for which all terms are known now could expose the Company to significant financial risk. PEF has filed the final versions of the SESH contracts with final terms and conditions set forth therein and all material facts regarding these long-term contracts that are known at this time have been presented to the Commission. As the Commission knows, these types of costs were already found to be of a nature recoverable through the fuel clause for FPL in Docket No.

060001-EI. There is past PSC precedent and policy with regard to seeking pre-approval of the terms and conditions of long-term fuel related contracts. Further, everything the Commission needs to make a decision on this matter is currently available. It is important to note that PEF is not requesting the Commission to approve anything with regard to the future management of these contracts. Rather, PEF is only requesting the Commission find that entering into these contracts was a prudent decision based on the facts known at the time the contracts were executed.

B.) Why would Commission approval of the long-term fuel supply and transportation contracts be in the public interest?

PEF's Response: Approval of the long-term contracts is in the best interest of the public for several reasons. Absent these contracts, by 2009, approximately 78% of PEF's transportation capacity will be sourced from the off-shore Mobile Bay area. The SESH contracts will cut our projected reliance on off-shore Gulf of Mexico production in 2009 by half. This is important due to the fact that demand for gas is projected to increase significantly in the future, while production from the Mobile Bay area is decreasing. With this in mind, it is prudent for PEF to seek out and have available alternate production supply. In addition, the production in the off-shore Mobile Bay area is highly susceptible to prolonged shut downs during extreme weather events. This was illustrated in the 2005 storm season and is discussed in some depth in the report titled "Impact of the 2005 Hurricanes on the Natural Gas Industry in the Gulf of Mexico Region" produced by the DOE, a copy of which is provided herewith as **Exhibit A**. The Southeast Supply Header will provide access to on-shore natural gas supply basins. It is important to understand that the transportation from Mobile Bay into the State of Florida has been very reliable during extreme weather events, it is primarily the production that has been significantly impacted. This new source would offset the risk associated with natural gas supply interruptions from extreme weather events. Another benefit to the public interest is the potential for downward pressure on gas prices in the Mobile Bay area. PEF believes that adding access to extra supply will place downward pressure on the price for natural gas coming out of the Mobile Bay area. One of the fundamental rules of economics is that with all else being equal, an increase in supply will decrease the market clearing price for a product.

C.) Please cite all relevant examples that PEF believes serves as precedent for the Commission approving fuel transportation contracts (as opposed to Commission approval of cost recovery only).

PEF's Response: In Docket No. 041414-EI, PEF filed a petition with the Commission requesting approval of the terms and conditions of the contracts with BG LNG Services, LLC, Southern Natural Gas Company and Florida Gas Transmission (the "Cypress Project") for long-term natural gas supply and transportation. The Commission approved the long term fuel supply and transportation contracts comprising the Cypress Project in Order No. PSC-05-0721-FOF-EI issued July 5, 2005. This is a particularly relevant example in that it had to do with contracts that were the best and most prudent alternative not based solely on price, but only after non-price factors were considered.

D.) If the Commission is being asked to approve a contract, shouldn't the Commission be involved in the contract negotiations between PEF and the contracting party?

PEF's Response: It is PEF's position that contract negotiations are a utility management function. The role of the Commission is to review and determine the prudence of such actions and the resulting contracts based on the facts known at the time the contracts are signed. If the Commission were involved in the negotiation process, it would hamper the ability of the Commission to serve in an objective, unbiased capacity in reviewing and determining the prudence of the contracts after the fact.

E.) If the answer to the above is yes, would this open the door to PEF inviting the Commission into other contractual negotiations and management decisions?

PEF's Response: N/A

F.) If Commission found portions of the language within the contract objectionable, would PEF amend the contract to include the Commission's concerns?

PEF's Response: The contracts represent a lengthy process of evaluation and negotiation between PEF and the counterparty. If the Commission found certain language objectionable, PEF would first try to explain why the language is in place and try to alleviate the Commission's concerns. If the Commission still had problems with the language, PEF would look into any feasible options to address the Commission's concerns including possible language modification. That being said, it is important to understand that these contracts represent extended negotiations that are difficult to modify where both sides have had to compromise on various, interrelated provisions. A unilateral modification imposed by the Commission could impact the negotiated balance of considerations each party provides and receives under these negotiated agreements.

2. Please refer to Exhibit KF-2. Also refer to witness Fonvielle's testimony, page 9, lines 15 through 23 and continuing on to page 10, lines 1 through 7, and to page 7 of witness Portuondo's testimony:

A.) Other than the cost estimates represented on this schedule, are there any other costs associated with PEF's SESH project that are proposed to be charged to the fuel cost recovery clause? Please explain.

PEF's Response: Please refer to SESH's Pro Forma Tariff (hereinafter referred to as the "Tariff"), attached hereto as **Exhibit B**. PEF anticipates recovery of the variable usage rates referenced in Rate Schedule FTS Section 3.2(c) and further defined in Sections 8 and 22 of the Tariff (Original Sheet Nos. 9, 71, 92, 93, 94 and 95). In addition to normally recurring pipeline fixed and variable charges, PEF would be subject to non-recurring charges such as the penalty charges defined in Sections 13.8 and 23.4

of the Tariff (Original Sheet Nos. 83 and 97), and other charges specifically approved by FERC in the future.

B.) On page 9 of witness Fonvielle's testimony, lines 17 through 19, he states the following: "PEF's participation in the SESH Pipeline Project will result in, but not be limited to, two types of invoiced costs to be passed through the fuel clause: (1) fixed demand costs and, (2) variable commodity costs." Why would PEF not limit the costs proposed to be passed through the fuel cost recovery clause to these two components?

__PEF's Response:__ As stated in Section 3.2 of the proposed Rate Schedule FTS (see Sheet No. 9 of the Tariff attached hereto as **Exhibit B**), there are other applicable charges and surcharges that are contemplated but not currently known at this time referenced in Sections 8 and 22 of the proposed Tariff General Terms and Conditions.

C.) What other known costs or potential costs does witness Fonvielle propose for recovery through the fuel cost recovery clause?

__PEF's Response:__ None known or currently unknown that have not been addressed in PEF's responses to the above referenced Requests Nos. 2(A) and 2(B).

D.) Please provide an analysis of the variable costs on KF-2 showing the rates and calculation of the variable costs and stating all assumptions.

__PEF's Response:__ The variable costs shown on Exhibit KF-2 are comprised of the following three components:

[redacted]

Key assumptions used in PEF's model are shown on Appendix A, page 16 of the Business Analysis Package attached as **Confidential Exhibit C.**

E.) Has the FERC set recourse rates for the SESH pipeline? If yes, what are these rates? If no, when does PEF expect the FERC to set recourse rates for the SESH pipeline?

PEF's Response: No. The Tariff was filed as Exhibit "P" to the SESH Certificate Application filed with FERC on December 18, 2006. It is typical for FERC to approve the proposed tariff at the time the 7c Certificate is approved and issued. As to when it will be approved, this question can only be answered by the FERC.

Recourse rates as filed are shown on the Tariff Original Sheet Nos. 4, 5, and 6.

- FTS Max Reservation Rate (Fixed Cost) = $.3827/dt (100% LF Rate)
- FTS Usage-1 Rate (Variable Cost) = $.0064/dt
- FTS ACA Surcharge (Variable Cost) = $.0000/dt (see Original Sheet No. 93, Section 22.1)

Gas Transporters Use (%) (Variable Fuel Retention = 0.70% (will be a fuel tracker with annual true-up, see Tariff Original Sheet No. 94, Section 22.2)

3. Four new LNG import terminals are proposed for the Gulf coast (Conoco, Freeport, TX; Exxon, Ingleside, TX; Sempra, Hackberry, LA; Cheniere, Sabine, LA). Also, AES has proposed a LNG import terminal for the Bahamas. These proposed terminals are expected to begin service by 2010:

A.) If these new terminals begin service as proposed, what effect will that have on the Southeast Supply Header pipeline?

PEF's Response: If new LNG terminals are eventually permitted and constructed in the Gulf region, they should provide incremental supply to many interstate pipelines including pipelines that are planned to be interconnected o the SESH pipeline. PEF would be able to access this incremental supply directly or indirectly through the SESH pipeline capacity.

B.) What effect will new LNG terminals on the Gulf coast have on PEF's use of the SESH for supply?

PEF's Response: The effect of additional LNG supply in the Gulf region cannot be known at this time. As with domestic supply sources, LNG supply is and will likely continue to be sold at a price that will fluctuate daily based on an observable market index, such as the NYMEX Henry Hub contract, with a basis differential to account for locational differences. As stated in response to question 3(A) above, PEF would have direct or indirect access to Gulf LNG supply and could contract for this supply potentially utilizing the SESH pipeline if it is the best cost option after considering all price and non-price terms.

C.) For each LNG terminal project listed above, what is PEF's current understanding of the status of the project?

PEF's Response: The following information was obtained from each company's website and from FERC filing documents.

ConocoPhillips, Freeport, TX

- In late 2004 , ConocoPhillips signed an agreement with Freeport LNG Development, LP to participate in the proposed Quintanna (Freeport), TX terminal.
- Federal Energy Regulatory Commission (FERC)
  FERC Application in Docket No.: CP03-75-000
- Construction Status (as filed by ConocoPhillips on January 11, 2007)

Activity	% Completion
Storage and Vaporation	
Tanks	52.9%
Balance of Plant	41.5%
Marine Terminal & Berthing Area	78.4%
Pipeline	98.7%
Wetland Mitigation	95.0%

Expected to be in service in Early 2008.

- The Project will connect directly with Kinder Morgan TX, Houston Pipeline and Dow Pipeline. It will indirectly interconnect to FGT via Kinder Morgan TX and Houston Pipeline at existing interconnects in Texas. There will be no direct connection with Gulfstream Natural Gas System.

- Freeport LNG Expansion L.P.'s FERC Application, Docket No.: CP05-361-000.

- Filed with FERC on May 26, 2005.

Exxon, Ingleside (Vista Del Sol), TX

- Vista Del Sol LNG Terminal located in San Patricio County, TX
- Filed in FERC Docket No. CP04-395-000
- FERC Order issuing Certificate issued on June 20, 2005
- Facility will be connected with Vista del Sol Pipeline (25 miles in length)
- There is no direct connection with either FGT or Gulfstream Natural Gas System planned.
- The facility is expected to be operational in the 2008/09 timeframe, with a processing capacity of 1 billion cubic feet per day (bcfd) of LNG.
- No construction activity to date.
- Possible sale of project to a Dutch subsidiary of the Carlyle Group and Riverstone Holdings as reported in the Friday, January 12, 2007, Gas Daily.

Sempra, (Cameron LNG Terminal) Hackberry, LA

- Cameron LNG Terminal located in Cameron Ph, LA
- Filed in FERC Docket No. CP02-378-000
- FERC Order issuing Certificate on September 11, 2003
- The Cameron LNG receipt terminal and associated facilities will be built in Cameron, Louisiana, which is located approximately 148 miles east of Houston, Texas, and 230 miles west of New Orleans, Louisiana. The $750 million project will have the capacity to regasify up to 1.5 billion cubic feet (Bcf) of natural gas per day, and the site can accommodate expansion up to 2.65 Bcf per day. The terminal is projected to begin commercial operations in late 2008.

- On Aug. 1, 2005, Sempra LNG signed a 20-year Capacity Agreement with ENI S.p.A. for 40% of the capacity of the Cameron LNG receipt terminal (approximately 600 Mmcfd).

- The Engineering, Construction and Procurement (EPC) contract was signed in December 2004 with the joint venture Aker Kvaerner / IHI. A Notice To Proceed with construction was granted in August 2005.

- Construction at the Cameron LNG terminal site began in September 2005.

- The FERC application was submitted in December 2005, requesting approval to expand to 2.65 Bcf/d send out capacity.

- In addition to the terminal, Sempra Pipelines & Storage will also be constructing a 35-mile pipeline to transport natural gas from the facility to connect with existing interstate pipelines to the north which will include an interconnect with FGT in Calcasieu Ph, LA. It will not connect directly with Gulfstream Natural Gas System.

Cheniere Energy, (Sabine Pass LNG) Sabine, TX

- Sabine Pass LNG Terminal located in Jefferson County, TX
- Filed on December 22, 2003, in FERC Docket No. CP04-47 et.al.
- FERC Order issuing Certificate issued on June 20, 2005
- Facility will be connected with Sabine Pass Pipeline (16 miles in length)
- The facility is expected to be operational in the 2008 timeframe, with a processing capacity of 2.6 billion cubic feet per day (bcfd) of LNG.
- The facility is to be expanded to accommodate an incremental 1.4 Bcf/d sendout and is expected to be operational in 2009.
- Cheniere will connect to a 16-mile pipeline from the Sabine Pass LNG terminal and expects the pipeline to be operational in the fourth quarter of 2007. This pipeline will commence at the proposed Sabine Pass LNG, L.P. LNG import terminal near Sabine Lake in Cameron Parish, Louisiana and will run eastward along a corridor that will allow for interconnection points with interstate and intrastate natural gas transmission pipelines in South Louisiana, including Natural Gas Pipeline Company of America, Transcontinental Gas Pipeline Corporation, Tennessee Gas Pipeline Company, Florida Gas Transmission Company (Cameron Ph, LA), and Bridgeline Holdings, L.P. The project will not interconnect with Gulfstream Natural Gas System.
- As of December 1, 2006, construction of the project is 50.9% complete.

AES LNG (Ocean Express Pipeline) Ocean Cay Terminal, Bahamas

- Filed with the FERC in February 2002 in Docket No. CP02-90
- LNG Terminal awaiting Bahamian Governmental Approval
- Construction has not started.
- The facility was expected to be operational in the 2008/09 timeframe but those dates appear very optimistic.
- On December 21, 2006, AES requested that the FERC grant a four (4) year extension of the in-service date to January 29, 2011, due to unexpected delays in securing final project approval from the Bahamian Government.
- Project's future remains uncertain.

4. Did PEF consider new LNG sources from new terminals on the Gulf coast as an alternative to the SESH project? Please explain.

PEF's Response: Yes. As mentioned on pages 11 and 12 of the Direct Testimony of Kent Fonvielle and page 9 of the Business Analysis Package attached hereto as **Confidential Exhibit C**, PEF considered potential LNG sources in the Gulf region as well as additional LNG from the Elba Island LNG terminal.

While additional LNG will further reduce PEF's dependence on offshore Mobile Bay area production, by 2009 existing LNG contracts with BG will make up [redacted] percent of PEF's overall supply portfolio. Therefore, purchasing additional LNG supplies will not in and of itself increase supply diversity. Additionally, LNG cargos can be re-routed during situations when prices are more favorable in world markets other than the United States (i.e., gas prices more attractive in Europe). Furthermore, Gulf LNG terminals would likely experience the same disruptions, simultaneous with curtailments of offshore production, due to extreme weather events in the Gulf. Finally, when compared to onshore supply, LNG introduces incremental geopolitical risks, where the curtailment of gas exports could occur due to foreign country events such as strikes, wars, terrorism, etc.

5. Please refer to page 6, lines 12 through 16, of Javier Portuondo's testimony and to Kent Fonvielle's testimony, page 7, lines 14 through 21 and continuing on to page 8, lines 1 through 6. For gas to meet increasing gas requirements, what are PEF's plans for transporting this additional gas on pipelines in Florida? As part of this answer, please provide a schedule showing additional firm pipeline capacity for the years 2008 through 2012.

PEF's Response: With the SESH pipeline capacity PEF will begin purchasing a portion of its natural gas in the Perryville Hub area. This onshore gas will be transported to the Mobile Bay area using the SESH pipeline, where it will feed into the two existing interstate pipelines that supply gas to the State of Florida: Florida Gas Transmission and Gulfstream Natural Gas System. PEF will use its firm transportation rights on FGT and Gulfstream to transport this gas to its plants in Florida. Additional firm pipeline capacity currently under contract for PEF is shown in the table below. The capacity on each pipeline during a specific period is as stated and is not additive to earlier periods shown.

[redacted]

6. Please refer to page 6 of witness Portuondo's testimony, lines 9 through 16 and to page 9, lines 4 through 12 of witness Fonvielle's testimony regarding potential savings for PEF's customers as a result of the SESH project. Also, regarding costs, please refer to page 7 of witness Portuondo's testimony and to page 9 of witness Fonvielle's testimony, lines 15 through 23 and continuing on to page 10, lines 1 through 7.

A.) Please explain how the potential savings are calculated. Include total savings, how the savings were calculated, and the comparison to PEF's estimated annual project costs.

PEF's Response: As can be seen from the graph on page 6 of the attached Business Analysis Package, the Mobile Bay basis (premium above NYMEX) has been increasing over the past few years. Basis increases during periods when demand for gas outstrips supply in a given region. Therefore, new infrastructure projects such as the SESH pipeline that increase available supply, should help to suppress the increasing basis and may act to lower the basis over time. The actual future basis, with and without the incremental supply brought to the region by the proposed SESH pipeline, is not known and therefore PEF cannot calculate these potential savings.

A second opportunity to create savings is to procure gas supply via the SESH pipeline in the Perryville Hub area at a basis lower than the Mobile Bay basis. [redacted]

[redacted]

B.) How can the SESH project potentially cause a lower overall cost of gas for PEF's customers?

PEF's Response: See response to 6(A) above.

C.) Will the SESH project increase PEF's delivered price of gas? Please explain.

PEF's Response: The future cost of natural gas delivered to PEF's generating plants is affected by many variables, but is primarily driven by changes in the underlying commodity price as measured by the NYMEX contract. PEF will continue to manage volatility in the price of gas through our hedging program. In addition, PEF will seek to offset the increase in fixed pipeline costs through procurement strategies such as those described in 6(A) above.

7. Will the SESH project allow PEF to negotiate better non-price terms for natural gas supply contracts? Please explain.

PEF's Response: The SESH project will not necessarily lead to better non-price terms in future gas supply deals, although it will increase the pool of suppliers available to PEF and thus increase competition. In addition, the onshore gas available via the SESH capacity will be less subject to disruption from severe weather events affecting offshore production platforms.

8. Will the SESH project cause PEF to buy less off-shore gas? Please explain.

PEF's Response: Yes. The SESH capacity will allow PEF to buy less offshore gas than otherwise would be required to support the gas generation fleet in the future.

9. What part of new PEF demand for natural gas will be supplied by Mobile Bay?

PEF's Response: The following table depicts the contribution of each supply region as a percentage of PEF's projected gas usage over time. PEF's projected gas usage includes existing gas-fired generation and planned gas-fired generating units.

	2007	2008	2009	2010	2011	2012
Mobile Bay/ Destin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FGT Z1&2						
Cypress/LNG						
Perryville/Carthage						
Total	100%	100%	100%	100%	100%	100%

10. PEF's proposed share of the SESH project capacity is 200,000 MMBtu by 2009. The projected in-service date is around mid-2008.

PEF's Response: PEF's proposed share of SESH project capacity is as follows:

6/1/2008 – 5/31/2009:	100,000 Dths/day
6/1/2009 – 5/31/2010:	150,000 Dths/day
6/1/2010 – 5/31/2022:	200,000 Dths/day
6/1/2022 – 5/31/2023:	50,000 Dths/day

A.) As of the SESH project's mid-2008 in-service date, does PEF intend to fully use the 200,000 MMBtu firm capacity?

PEF's Response: [redacted]

B.) Will PEF have excess capacity initially or at various times? If no, please explain. If yes, what are PEF's plans for the excess capacity?

PEF's Response: [redacted]

C.) Referring to Exhibit KF-2, please provide the analysis assuming 80% and 90% utilization of pipeline capacity.

PEF's Response: See attached **Confidential Exhibits D and E** which show projected annual costs assuming 80% and 90% utilization, respectively.

D.) How will PEF's participation in the SESH project be affected if the proposed in-service date is moved back to the end of 2008?

PEF's Response: PEF's contract with SESH has several conditions precedent to monitor progress of the project and allow termination of the contract if certain critical milestones are not met. Assuming these earlier milestones are met, PEF would begin taking service at the later in-service date of the project.

E.) What is the SESH pipeline project's status regarding FERC regulatory approval? As part of the response to this question, please provide a timeline of the significant FERC regulatory actions, both historical and expected.

PEF's Response:

- National Environmental Policy Act (NEPA) pre-filing filed in Docket No. PF06-28
- NEPA pre-filing request submitted on May 5, 2006
- Certificate application was filed by SESH with the FERC on December 18, 2006
- Docket Nos. CP07-44, CP07-45, CP07-46 and CP07-47 were assigned to the subject NGA Section 7c Certificate Application
- Noticed by the FERC on December 28, 2006 with a comment deadline date of January 18, 2007. Likely will take eight (8) months for approval from FERC but only FERC knows how long it will take. (See FERC Notice attached hereto as **Exhibit F**)

F.) Other than FERC regulatory approval, are there remaining regulatory approvals for the SESH pipeline project? If yes, please provide a summary of the remaining regulatory approvals.

PEF's Response: This information is not known to PEF but is likely available from SESH.

11. If the Commission chooses to move consideration of this petition past the March 13, 2007 Agenda Conference, what risks would this create for PEF regarding terms in the contract and whether PEF would proceed with the contract/project?

PEF's Response: [redacted]

[redacted]

12. Please refer to Kent Fonvielle's testimony, page 10, lines 8 through 22, and pages 11 and 12. Of the various options that PEF considered, was the SESH the lowest cost alternative? Please explain. Also, provide an analysis showing the cost of each alternative considered.

<u>PEF's Response</u>: No. Although SESH was not the lowest cost alternative, it was determined to be the most cost-effective option considering all price and non-price factors as further described below.

[redacted]

[redacted]

13. Please provide complete copies of any studies or analyses done by PEF or on behalf of PEF since January 1, 2005 that consider LNG as a future source of supply of natural gas for PEF.

<u>PEF's Response</u>: See page 9 of the attached Business Analysis Package.

14. Please provide complete copies of any cost/benefit analyses that justify the SESH project as the lowest cost alternative for new natural gas supply for PEF.

<u>PEF's Response</u>: See pages 10 & 11 of the attached Business Analysis Package.

15. Please provide complete copies of any cost/benefit analyses or savings calculations regarding the SESH project's potential to result in savings for customers.

PEF's Response: Please refer to pages 3 – 7 of the attached Business Analysis Package for a discussion of the overall benefits of the SESH pipeline project. Also, please refer to response to question 6(A) and to pages 23 - 24 of the attached Business Analysis Package for a discussion and analysis of potential savings that may be derived.

16. Please refer to page 6 of witness Portuondo's testimony, lines 9 through 16 and to page 9, lines 4 through 12 of witness Fonvielle's testimony. Please provide any analyses of the impact the SESH project will have on gas prices in the Mobile Bay area. Also, please provide copies of any documentation that these witnesses relied upon in making these specific statements about savings and "lower overall cost of gas for PEF's customers."

PEF's Response: PEF has done no formal analysis of the impact the SESH project will have on gas prices in the Mobile Bay area. This project is not being proposed to lower the price of gas available in Mobile Bay. Absent any price impact on natural gas out of Mobile Bay, PEF believes this is a worthwhile project and will benefit PEF's customers through improved reliability and supply diversity. With regard to the statements referenced above in witness Portuondo and Fonvielle's testimony, our belief that there may be a positive impact on the price of gas out of Mobile Bay is founded in economic theory. The law of supply and demand dictates that with all else equal, an increase in supply will result in a lower market clearing price for a commodity. In fact, the existence of OPEC illustrates the influence supply of a commodity can have on its price. This pipeline will increase the supply of gas available to the Mobile Bay area as well as anyone connecting to the Mobile Bay area. While it is not possible to make a reliable prediction on price impact, it makes sense that at any given point in the future, with demand for natural gas at a given level, one would expect the price coming out of Mobile Bay to be lower with an increased supply available.

17. Please provide complete copies of all workpapers, analyses, and source documents associated with the testimony and exhibits of Javier Portuondo.

PEF's Response: Documents relied on concerning the purpose and scope of the SESH project are being provided as part of the response to question number 18. Please see copy of the DEP report titled "Florida's Energy Plan" issued on January 17, 2006 referenced in Mr. Portuondo's testimony, attached hereto as **Exhibit G**. Please also see the copy of the DOE report titled "Impact of the 2005 Hurricanes on the Natural Gas Industry in the Gulf of Mexico Region", attached as **Exhibit A**. This report contains useful background information with regard to natural gas production and susceptibility to extreme weather events which was considered as Mr. Portuondo's testimony was prepared.

18. Please provide complete copies of all workpapers, analyses, and source documents associated with the testimony and exhibits of Kent Fonvielle.

<u>PEF's Response</u>: See attached files. (**Exhibit H**).

19. Please provide complete copies of studies done by or for PEF addressing gas procurement reliability and SESH.

<u>PEF's Response</u>: See attached files. (**Confidential Exhibit C**).

20. Please provide a copy of Section 3 of Rate Schedule FTS included in the Transporter's tariff.

<u>PEF's Response</u>: Please see PEF's response to Request No. 2F above and the Tariff attached hereto as **Exhibit B**. Section 3 of Rate Schedule FTS is contained in Original Sheet Nos. 9, 10, and 11.

Sincerely,

Kenneth A. Hoffman
Co-Counsel for Progress Energy Florida, Inc.

KAH/rl
cc: John Burnett, Esq., Co-Counsel for Progress Energy Florida, Inc.

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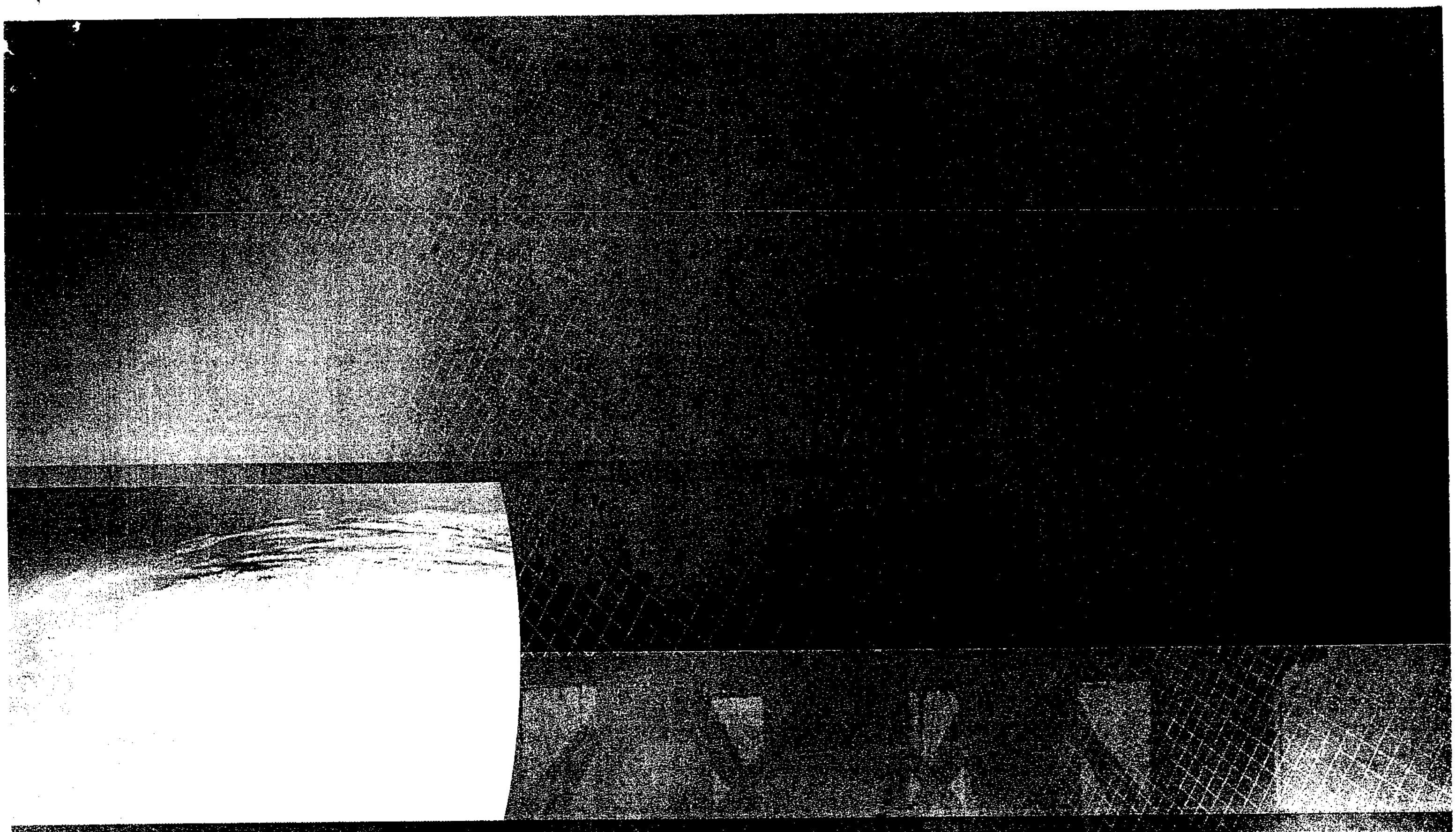

IMPACT OF THE 2005 HURRICANES
ON THE NATURAL GAS INDUSTRY
IN THE GULF OF MEXICO REGION

DEPARTMENT OF ENERGY
UNITED STATES OF AMERICA

EXHIBIT
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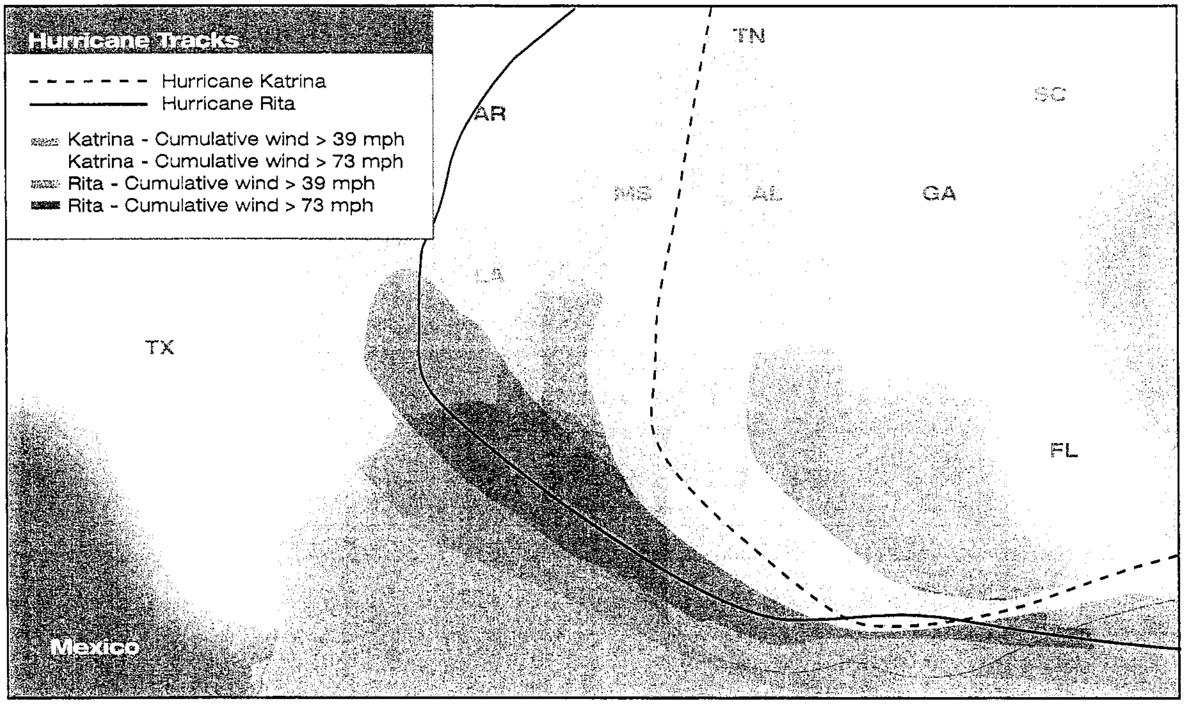
PATHS OF HURRICANE KATRINA AND RITA



About This Report

This report was prepared by the U.S. Department of Energy's Office of Fossil Energy with support from the Energy Information Administration's Office of Oil and Gas. The Office of Fossil Energy supports technology research and policy options to ensure clean, reliable and affordable supplies of oil and natural gas for American consumers working closely with the National Energy Technology Laboratory, which is the Department's lead center for the research and development of advanced fossil energy technologies. The Energy Information Administration (EIA) is the independent statistical and analytical agency within the Department of Energy.

Design and Editorial Support

Science Applications International Corporation (SAIC)

Select photos and graphics courtesy of: Enbridge Offshore Pipelines, LLC; Enterprise Products Partners, LP; Excelerate Energy, LLC; Panhandle Energy Company; and Technology & Management Service, Inc. (TMS)

Executive Summary

This report summarizes the findings of the Department of Energy's (DOE) monitoring of the impact of hurricanes Katrina and Rita on the natural gas industry in the Gulf of Mexico region from late August 2005 through early March 2006. During that time, DOE coordinated with other Federal agencies and various natural gas industry personnel to track storm recovery efforts on a daily basis and identify disrupted natural gas flows and possible bypasses.

These monitoring efforts provided further insights into the complex supply delivery operation associated with offshore natural gas production. They also highlighted the importance of accurate, timely data and identified specific data elements that would be pertinent during other supply-related emergencies. Some of these lessons learned are particularly relevant as another hurricane season is underway.

Hurricanes and tropical storms are plentiful in the Gulf of Mexico, which is a major source of U.S. natural gas. The Federal Outer Continental Shelf (OCS) in the Gulf of Mexico provides about 10 billion cubic feet (Bcf) of gas per day or 20 percent of all the natural gas produced domestically. In a 4-week period in August and September 2005, hurricanes Katrina and Rita dealt a one-two punch to natural gas industry operations in the Gulf region. All aspects of the industry were affected, with the storms causing destruction and substantial damage to offshore production platforms and pipelines as well as onshore production wells, pipelines, processing plants, and other infrastructure supporting the Gulf production and delivery system.

The Minerals Management Service (MMS) estimated that 3,050 of the Gulf's 4,000 platforms and 22,000 of the 33,000 miles of Gulf pipelines were in the direct path of either Hurricane Katrina or Hurricane Rita. In addition, 47 major natural gas processing plants and 17 natural gas liquids fractionation sites located within the 70 counties and parishes along the Gulf Coast of Texas, Louisiana, Mississippi, and Alabama were threatened by the storms' approach. These facilities have the capacity to process 22.8 Bcf per day.

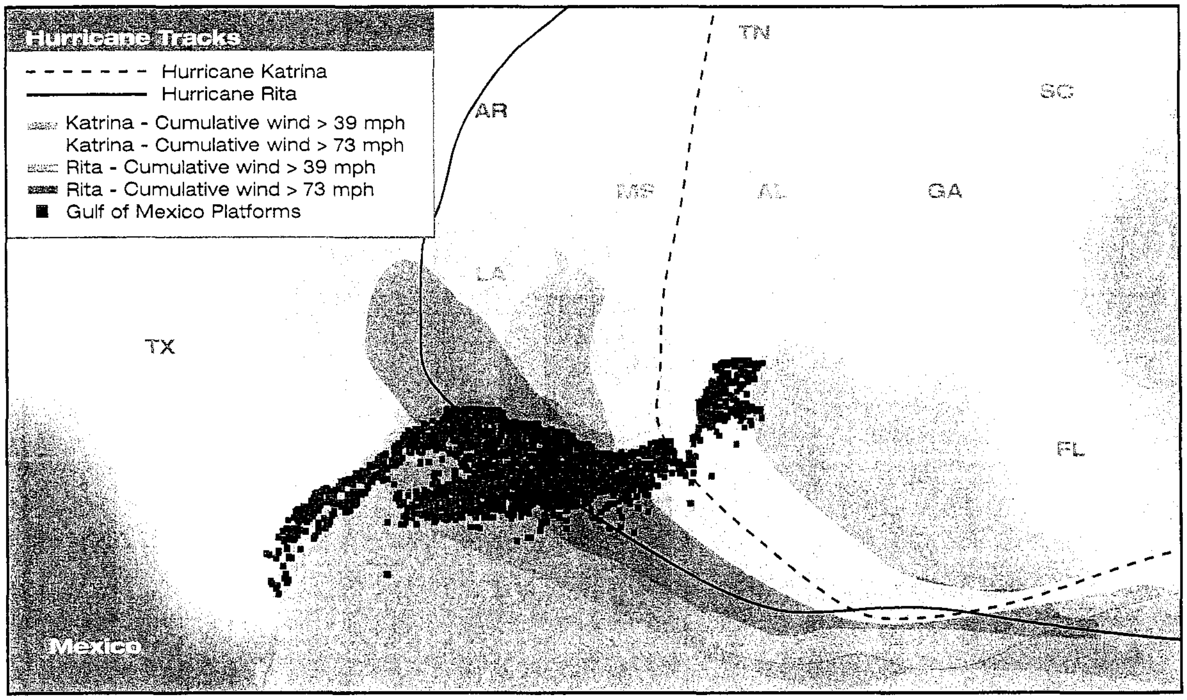


Figure 1. **Gulf Platforms and Paths of Hurricanes Katrina and Rita**

The damage from the two storms varied, but together caused the biggest disruption to operations that the industry has ever seen. Hurricane Katrina, which was a Category 5 storm (winds greater than 155 miles per hour) when it entered the Gulf in late August 2005, destroyed 44 platforms and damaged 20 others. It also damaged at least 100 pipelines in Federal waters (based on data as of March 8, 2006), 36 of which were large-diameter lines (10 inches or larger), and resulted in the shut-in of at least 8 natural gas processing plants.

Hurricane Rita, which was a Category 4 hurricane (winds between 131 and 155 miles per hour) when it entered the Gulf just a few weeks after Katrina, destroyed 69 platforms and damaged 32 others. It also damaged at least 83 offshore pipelines, 28 of which were large-diameter lines. As a consequence of both hurricanes, virtually all large natural gas processing plants in the area from Galveston Bay, Texas, through Mississippi were shut down. A total of 27 plants were affected, or nearly 75 percent of total processing capacity in the region, and operations were disrupted at several fractionators (natural gas liquids plants).

The offshore and onshore service industry supporting OCS natural gas production and deliveries was also devastated by the hurricanes. The network of work boats, crews, divers, supplies, and equipment needed to assess the damage and perform repairs to platforms and pipelines was shredded. In addition, docks and fleets were destroyed, electric power was lost on a wide-scale basis, and transportation fuels were not available for the boats, helicopters, and ground transportation vital to the recovery. Even the basic necessities of food, water, and shelter were not available in large areas of the hurricanes' impact zones. This damage to the support service industry hindered the natural gas industry's ability to recover from the storms.

Two liquefied natural gas (LNG) import terminals (the Panhandle Energy/Trunkline LNG terminal in Lake Charles, Louisiana, and Excelerate Energy's offshore LNG operation, Gulf Gateway Energy Bridge) were also in the paths of hurricanes Katrina and Rita but suffered little or no damage. However, the navigation channel to the Lake Charles terminal was closed for several days after Rita because of debris in the shipping channel, and gas gathering pipelines serving Gulf Gateway Energy Bridge LNG operations were affected by the storms.

Storm recovery efforts have highlighted the complexity and inter-relatedness of the natural gas supply industry. Natural gas in the Gulf comes from wells as deep as 5 miles below the water's surface. Offshore production platforms are connected to downstream facilities by a series of gathering pipelines that transport the natural gas produced at these points to progressively larger diameter lines. The largest-diameter lines transport the consolidated natural gas stream to onshore compression stations, dehydration and separation facilities, processing plants, and eventually to transmission lines for delivery to end users.

Damage to any of these components affects the others. For example, reduced production flow meant that some operational processing plants were inactive because they had no gas to process. In other cases, production flow had to be redirected around damaged processing plants to other facilities or to other pipelines with access to processing capability. At times pipeline flow directions were reversed and temporary bypasses were utilized. Since all aspects of the Gulf natural gas delivery system – production, pipelines, and processing – are tied closely together, the recovery process for each of these three links is tied to the recovery of the other two links.

As of March 8, 2006, when DOE ended its active monitoring of storm recovery efforts, production had returned to about 9 Bcf per day, and flow rates of primary pipelines within the hurricane impact area were stabilizing within normal ranges. All but 2[1] of the 47 gas processing plants in the area were operating, although at reduced flow levels in aggregate. The remaining damage to production platforms, pipelines, and related infrastructure was expected to take several months to repair. In some cases, the decision to repair or how to repair had not been made, or the priority to proceed was low, based on economic considerations.

Damage assessments and information about recovery efforts throughout the whole process, from production to pipelines to processing plants, were often difficult to obtain by DOE staff. This was because of concerns about competitive advantage, limiting the responses to requests for company-specific information, as well as the lack of information about the extent and effects of the damages given the enormous impacts of the hurricanes.

The MMS released almost daily reports of evacuation and production shut-in statistics for the platforms in the Federal OCS from late August until mid December and then weekly reports through the end of February, followed by biweekly reports until May 3, 2006, and two additional reports on June 1 and June 21, 2006. DOE combined the MMS production data with data on pipeline and processing plant damages and repairs to provide daily reports on the status of the whole production and delivery process. These daily reports also included input from industry contacts and web-based pipeline informational postings.

It is noteworthy that as late as early May, when MMS issued its final damage assessment report, operators were still revising assessments and evaluating the economics of repair, abandonment, or expansion. On May 1, 2006, MMS reported that, based on additional industry investigations and reports, more than twice the number of pipelines were damaged than had been identified in January (457 vs. 183), and the number of damaged primary lines was revised from 64 to 101. MMS also reported that shut-in gas production was almost 1.3 Bcf per day as of May 3, 2006, or about 13 percent of daily gas production in the Federal waters of the Gulf.

In its final shut-in statistics report on June 21, 2006, MMS estimated that about 9.4 percent of daily gas production remained shut in as of June 19, 2006. Cumulative shut-in gas production from August 26, 2005, through June 19, 2006, was 803.6 Bcf, which is equivalent to about 22 percent of yearly gas production in the Federal OCS in the Gulf.

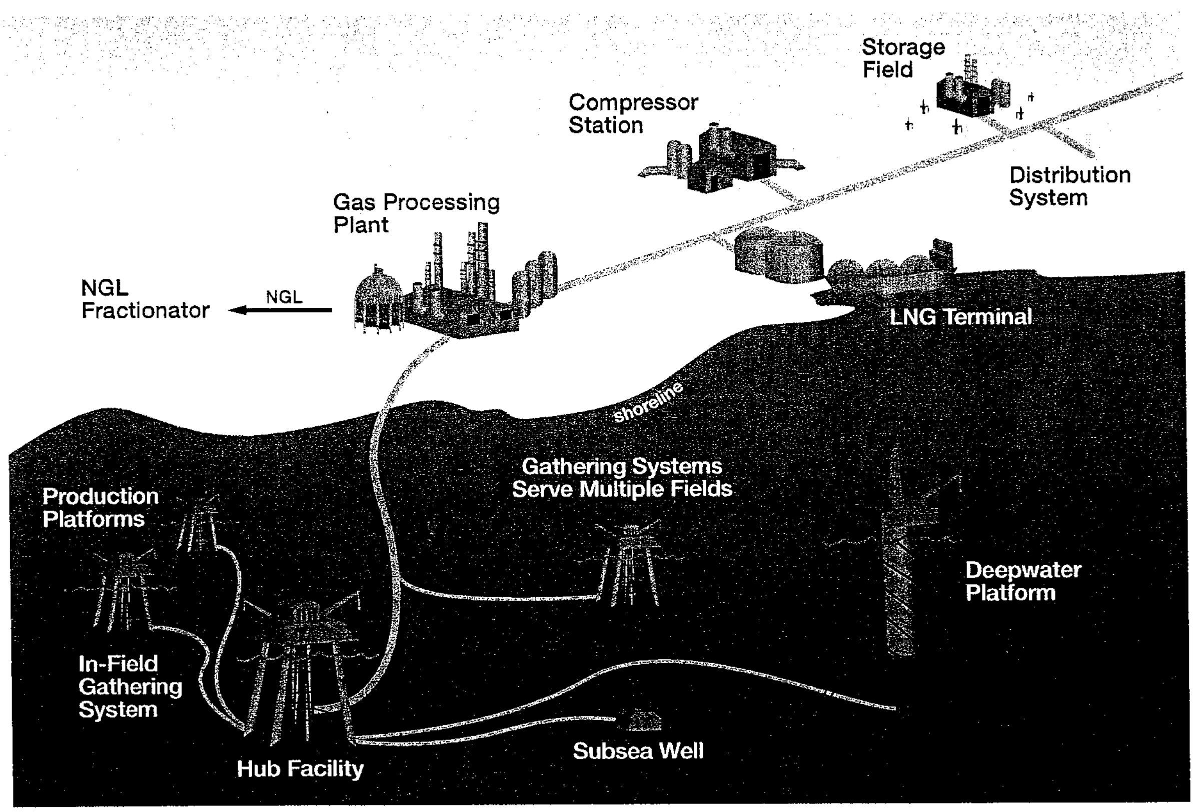
THE ABCS OF NATURAL GAS SUPPLY IN THE GULF REGION

Storm recovery efforts after hurricanes Katrina and Rita have highlighted the complexity and interrelatedness of the natural gas supply industry in the Gulf of Mexico region, as well as its flexibility. A highly complex infrastructure is required for producing natural gas offshore, gathering and moving the gas onshore, processing the gas and separating natural gas liquids, and delivering pipeline-quality gas to the long-distance transmission pipelines that transport natural gas to markets throughout the United States.

Compressor stations along the lines maintain the pressure to keep the gas flowing, and storage facilities feed and receive gas for system balancing and supply. The transmission lines serve a number of distribution company main lines that branch into yet smaller lines that serve residential, industrial and commercial customers. The Gulf of Mexico region also has two liquefied natural gas (LNG) import terminals, which play an important role in diversifying and expanding natural gas supplies. The LNG is transported by ship, stored at low temperatures and atmospheric pressure in super-insulated tanks, and then regasified and fed into the natural gas pipeline system.

Each element of this complex, integrated system is dependent upon adjacent elements, so damage to one

Figure 2 Gulf of Mexico Natural Gas Supply Schematic



portion of the system can affect the entire chain. The system is generally capable of dealing with short-term interruptions or disturbances, but the major disruptions in the aftermath of hurricanes Katrina and Rita required extensive industry coordination, particularly since support services were overloaded. Producers, pipelines, and processors had to work together to optimize repair efforts and move as much natural gas to market as possible. Understanding the basics of the natural gas supply process can help put these recovery efforts in context.

Production: The Gulf of Mexico region produces about 20 percent of U.S. natural gas

Oil and natural gas in the Gulf come from wells as deep as 5 miles below the water's surface. These wells flow to production platforms where the primary separation of gas, oil, and water is completed. The type of production platform depends on the water depth of the producing area.

Platforms in shallow water (less than 1,000 feet) are generally fixed platforms, compliant towers, or tension-leg platforms that are attached to the seafloor.

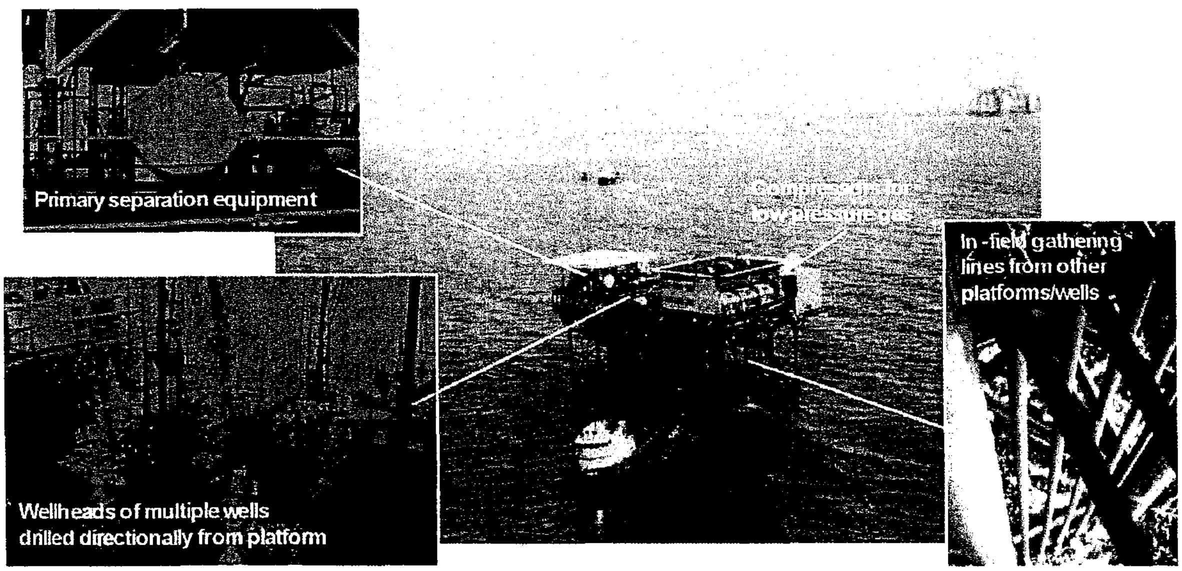
Platforms in deep water generally involve floating structures that can receive production from subsea wells. Deepwater platforms far offshore typically pipe gas and oil to a "hub platform" in shallower water before sending it to shore.

Typically 5 to 20 wells are drilled from production platforms, and there are about 4,000 platforms in the Gulf of Mexico. High-pressure gas (1,100 pounds per square inch) may go directly into a pipeline, while low-pressure gas must be compressed at a central platform.

Gathering: The Gulf Region has about 33,000 miles of gathering pipelines

A network of pipelines is used to collect the natural gas from multiple platforms in multiple fields and deliver it onshore through a process called gathering. The gathering system may include additional platforms, metering stations, compressors, and processing equipment. Gathering systems can serve multiple fields and multiple producers. A series of gathering pipelines transports the natural gas produced at the various points to progressively larger diameter lines.

Figure 3. Components of Shallow Water Gas Production Platforms



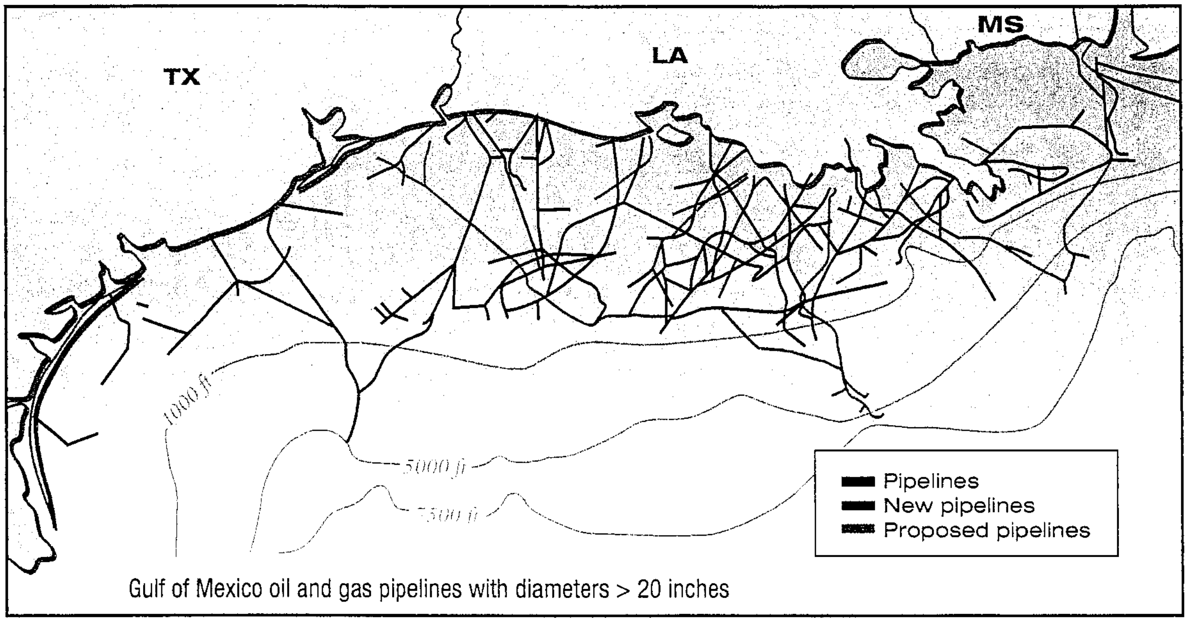


Figure 4. **Gathering Systems Collect Gas from Multiple Fields**

The largest-diameter lines transport the consolidated natural gas stream to onshore compression stations, dehydration and separation facilities, processing plants, and eventually to transmission lines for delivery to end users.

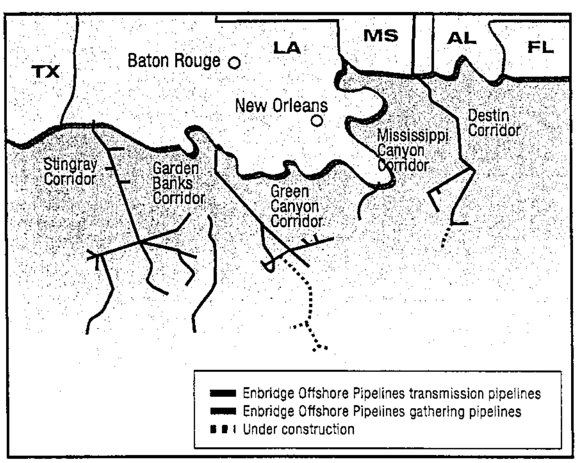


Figure 5. **Enbridge: One of Several Systems**

The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate transmission lines but not over gathering lines. In some cases, however, gathering systems may connect to transmission pipelines while still offshore. These offshore transmission lines provide distinct corridors for moving gas from multiple gathering systems.

Processing: **The Gulf Coast area has more than 45 major natural gas processing plants and 17 fractionators**

The consolidated gas stream from the Gulf moves to natural gas processing plants located onshore in the Gulf of Mexico coastal region, mainly in Louisiana and Texas. These natural gas plants process the gas to remove water, contaminants, and hydrocarbon liquids for the primary purpose of preparing the gas and liquids for end use by the consumer.

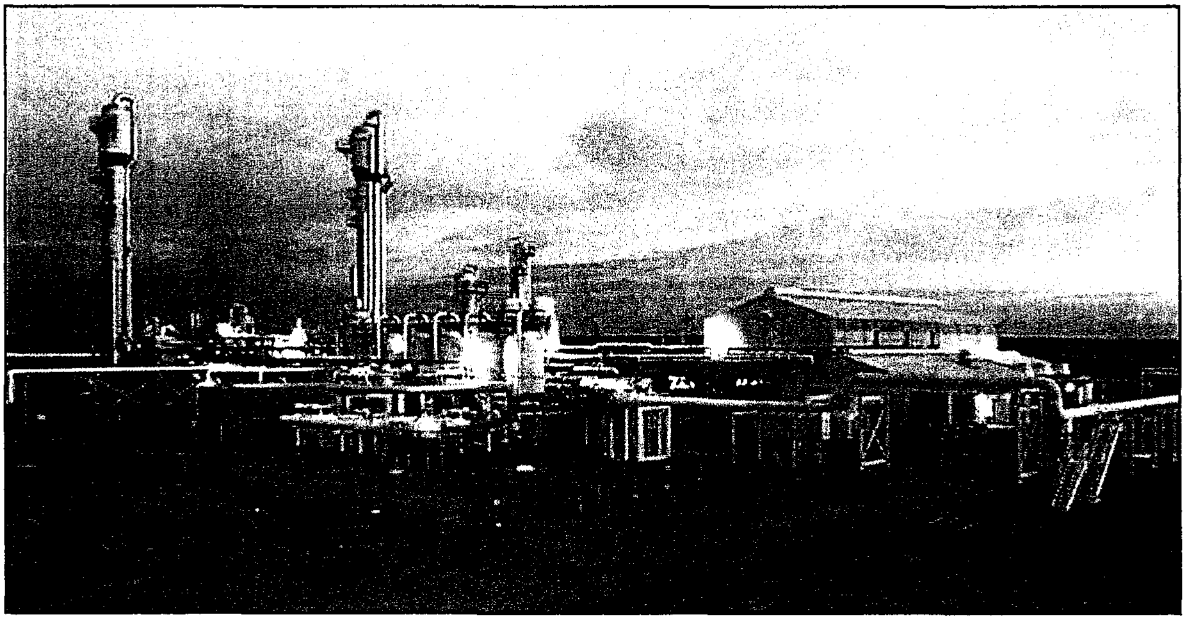


Figure 6. Enterprise Natural Gas Processing Plant

Some plants process gas from wells in state waters, marshlands, and onshore gas fields, as well as the gas from offshore fields. Gas from multiple gas gathering systems is dehydrated, "sweetened" (removal of hydrogen sulfide gas and carbon dioxide), and processed to remove heavier hydrocarbons such as ethane, propane, butane, and pentanes. These "natural gas liquids" (NGLs) are sent to a fractionator (by pipeline or truck), and the clean dry gas, which is now mostly methane, is metered, compressed, and sent to a transmission line.

The fractionation facilities' products are shipped to regional petroleum and petrochemical industry customers by pipeline, truck, and barge. The petroleum refining process also produces NGLs, and refineries often have fractionators, which may also process NGLs from gas plants.

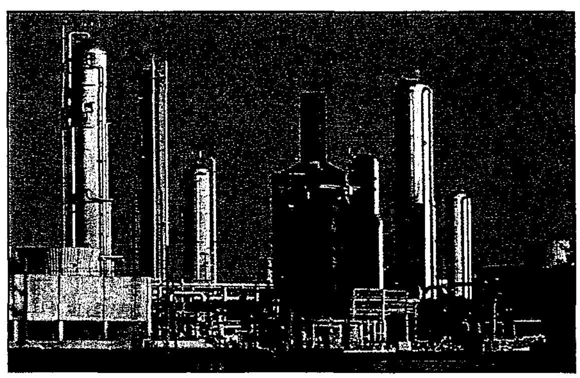


Figure 7. Promix Fractional Plant

Transmission, Storage and Distribution

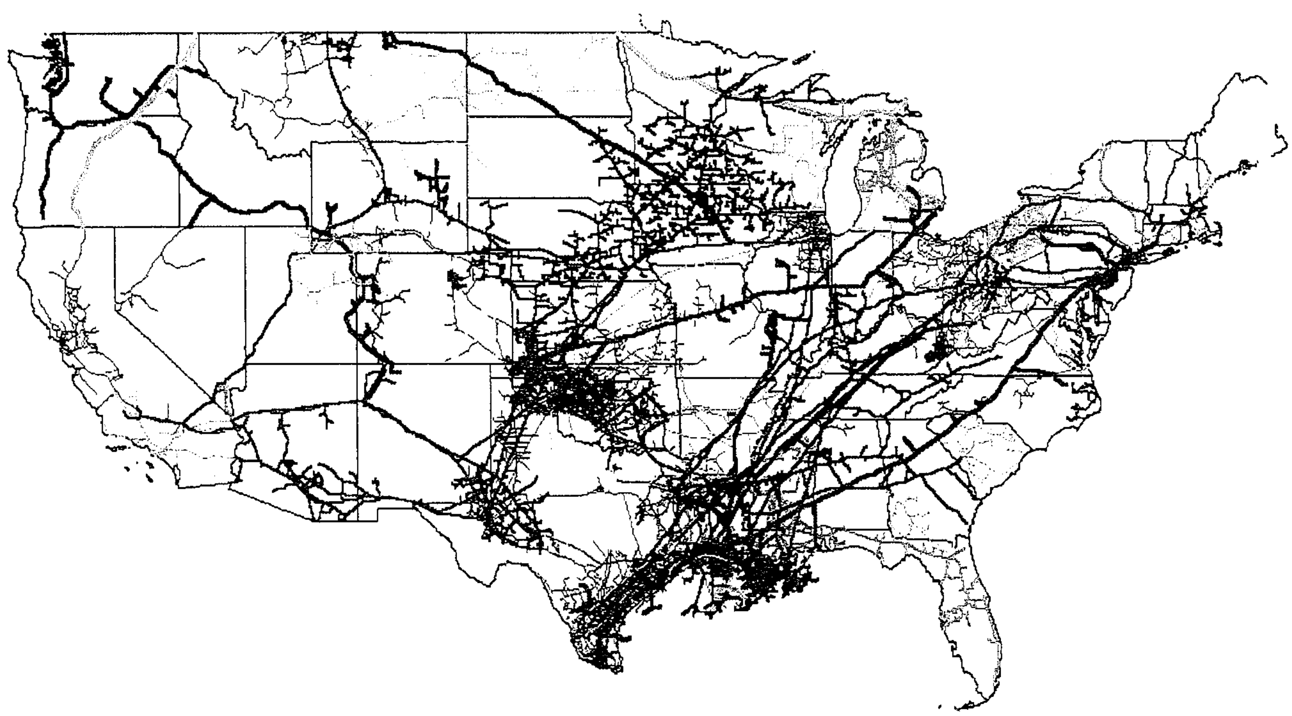
Major transmission lines link the Gulf Coast with points north and east and local distribution systems

Larger diameter pipelines are designed to transport volumes of natural gas from the Gulf of Mexico to markets in the Northeast, Midwest, and points in-between. A primary component of transmission lines are compressor stations that initially pressurize the gas feeding the lines and then recompress the gas at various points along the lines to maintain the line pressure and flow rate.

Gas storage facilities, found in both producing and consuming regions, feed the transmission system. Most storage in the Gulf region is in caverns formed in subsurface salt formations by dissolving with water. Market hubs have developed where multiple interstate pipelines meet, allowing for the efficient metering, storage, and trading of gas volumes among producers, pipelines, marketers, and customers.

The transmission lines also serve a number of distribution company main lines that branch into yet smaller lines which serve residential, industrial, and commercial customers. These distribution pipelines are regulated by state public utility commissions.

Figure 8. **Major Interstate Gas Pipelines Connect the Gulf Coast to Northeast and Midwest Markets**



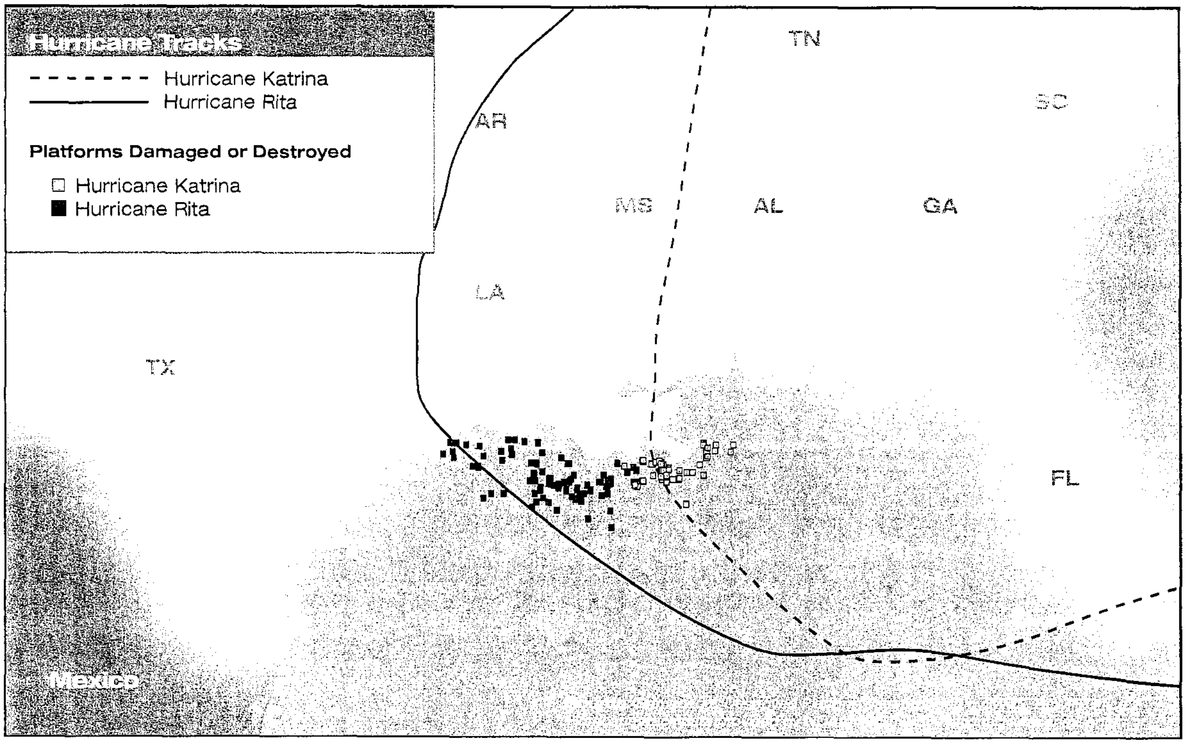


Figure 9 **Gulf Platforms Damaged or Destroyed by Hurricane Katrina or Hurricane Rita**

II. PRODUCTION

The Gulf of Mexico (Gulf) region is an important source of U.S. energy supply.[2] Before hurricanes Katrina and Rita, the Federal Outer Continental Shelf (OCS) in the Gulf provided about 27 percent (1.5 million barrels per day) of all the oil and 20 percent (10 billion cubic feet (Bcf) per day) of all the natural gas produced domestically.

Hurricanes Katrina and Rita cut right through the major oil and natural gas production operations in the Gulf. As noted earlier, an estimated 3,050 of the Gulf's 4,000 platforms were in the direct path of either Hurricane Katrina or Hurricane Rita. Virtually all production was shut-in in anticipation of the storms, and employees were evacuated from platforms and working rigs. According to the Minerals Management Service (MMS), more than 90 percent of the manned platforms and 85 percent of the working rigs were evacuated at one time.[3]

Damage Assessment

Because of the large amount of infrastructure in the storms' paths, damages from each of the hurricanes were extensive. Combined, the damages from the two hurricanes were far worse than anything previously experienced by the petroleum industry in the Gulf of Mexico. Hurricane Katrina, which was a Category 5 hurricane when it entered the Gulf, destroyed 44 platforms and damaged 20 others, while Hurricane Rita, which was a Category 4 storm when it entered the Gulf, destroyed 69 platforms and damaged 32 others (Figure 9). In comparison, only 7 platforms were destroyed when Hurricane Ivan hit the Gulf in 2004 as a Category 4 storm, because Ivan's path bypassed the major production infrastructure.

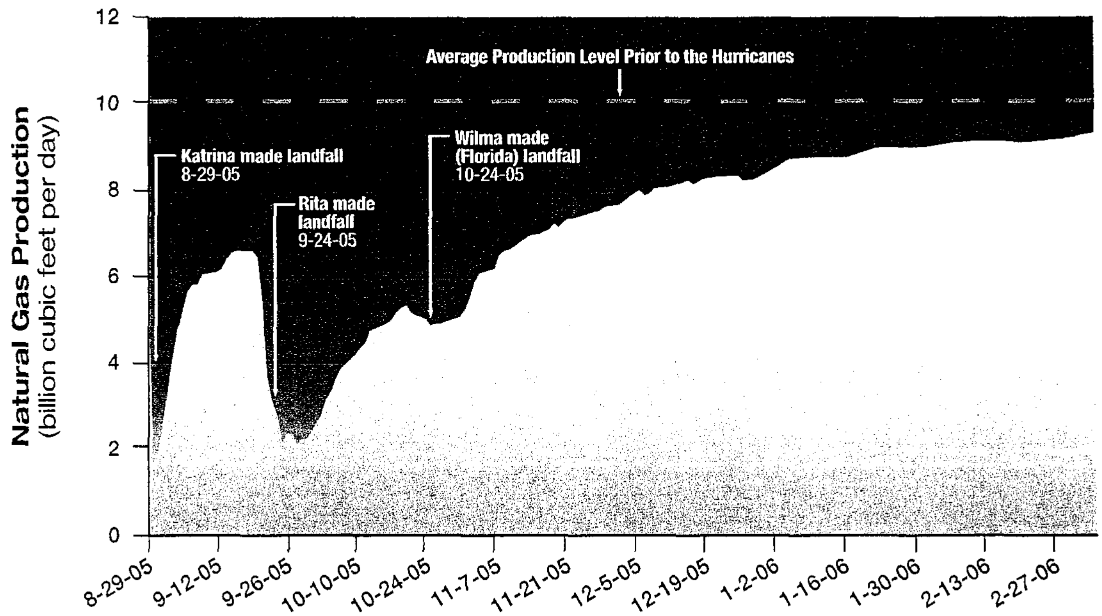


Figure 10. Federal Offshore Gulf of Mexico Natural Gas Production Recovery after the 2005 Hurricanes

Almost 80 percent of the destroyed platforms were older "end of life" platforms not built to MMS 1988 design standards. MMS does not expect these platforms, which represented less than 1 percent of the Gulf's gas production, to be repaired.[4] Repairs on the remaining destroyed platforms were expected to be completed no earlier than the summer of 2006. The same schedule applies to the platforms that sustained structural damage or required engineering services before repairs could begin.

Recovery

Natural gas production in the Gulf declined from an average of approximately 10 Bcf per day to less than 2 Bcf per day after Katrina made landfall on August 29, 2005 (Figure 10). This low point in Gulf gas production was a result of shutting down all the production platforms threatened by Katrina. Repairs were undertaken as soon as possible after the storm, and gas production returned to approximately 6.5 Bcf per day by mid-September. Then Hurricane Rita hit on September 24, 2005, further damaging some of the platforms recovering from Katrina and causing new damage in other parts of the Gulf. After Rita struck, Gulf gas production was reduced to about 2 Bcf per day.

The industry's initial recovery after the second of the two hurricanes, Rita, was slower than what it experienced after Katrina. While with Katrina, Gulf gas production rebounded to 6.5 Bcf per day within 3 weeks, after Rita, Gulf gas production did not reach 6.5 Bcf per day for almost 2 months.

Gulf gas production returned to 8 Bcf per day by the end of December 2005, and had reached about 9 Bcf per day as of March 8, 2006, as more difficult repairs and longer-term solutions were required. The remaining damage to production platforms and infrastructure will likely take several months to repair. MMS reported on May 1, 2006, that it has approved four replacement platforms that were proposed by operators to take the place of eight destroyed platforms. MMS also reported that shut-in gas production was less than 1 Bcf per day as of June 19, 2006, which is equivalent to about 9 percent of daily gas production in the Gulf.

III PIPELINE INFRASTRUCTURE

The pipeline system within the Gulf of Mexico (Gulf) comprises approximately 33,000 miles of pipelines that link the estimated 4,000 operating platforms to onshore elements. The hurricanes caused damage to and shut in most pipelines within more than 50 miles on either side of their respective paths. The pipeline system is composed of surface-level piping, valves, metering points, compressors, and dehydration and separation facilities, as well as sub-sea piping and valves, all working in harmony for the sole purpose of keeping natural gas flowing. Secondary lines (typically less than 20 inches) feed the larger diameter primary lines (20 to 36 inches in diameter) that transport the natural gas directly to points on shore.

Damage Assessment

The MMS estimated that 22,000 miles of pipeline were in the direct path of the two hurricanes. These pipelines transported approximately 67 percent of the natural gas produced in the Gulf. The path maps of Rita and Katrina indicate that the storms impacted the coast line at the west and east borders of Louisiana, respectively. If one were to draw a line 50 miles west of Rita's path and another 50 miles east of Katrina's path, the area bounded by these two lines would represent the area with the majority of the storm damage (Figure 11).

Approximately three dozen primary pipelines transport natural gas from the Gulf to the shorelines of Louisiana, Texas, Mississippi, and Alabama. Two-thirds of these primary lines enter Louisiana and thus were within the hurricane impact area. Most primary lines in the hurricane impact area experienced damage from the storms that either restricted or completely halted operations.

Most of the secondary lines were also located within the hurricane impact area and experienced similar levels of damage to those of the primary lines. At least two secondary lines in the Mobile Bay Area, located approximately 25 miles outside of the hurricane impact zone, experienced damage.

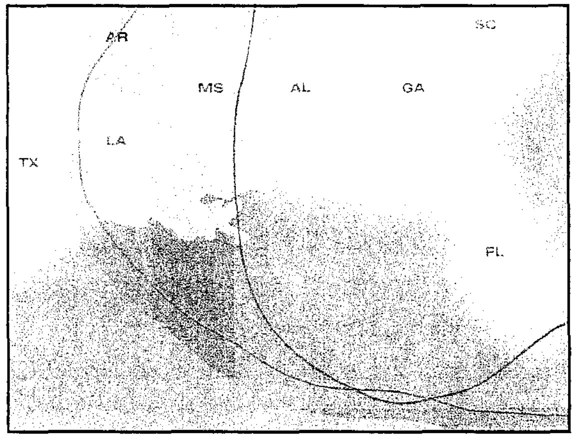


Figure 11. Hurricane Impact Area

The dozen or so primary lines located outside the hurricane impact area transport gas to Mississippi, Alabama, and Texas. Most of these pipelines had minimal damage from the storms and were fully operational when the platforms and processing plants in these areas resumed service.

The damage from the two storms to the pipelines varied in pattern, but there was a degree of similarity. In general, approximately half of the pipeline breaches occurred within an area that also experienced damaged or destroyed platforms.

All but a half dozen of the pipeline breaches occurred in the waters of the continental shelf (i.e., in water depths of 200 feet or less) with half of the continental shelf breaches located within 25 miles of the transition from deep water. As the continental shelf is closer to the shoreline in the eastern part of the hurricane impact area, approximately half of the breaches occurred within 25 miles of the shoreline in South Timberline and Main Pass areas or in the waters surrounding the Plaquemines Peninsula and Lafourche Parish.

Katrina caused almost double the number of natural gas pipeline breaches caused by Rita. Katrina's breaches, being in the eastern portion of the damage area, generally occurred closer to the shore, while the pipeline breaches caused by Rita were more randomly distributed along the path of the hurricane.

Recovery

Under normal conditions, primary and secondary pipelines flow at 50 to 60 percent of design capacity; however, the actual utilization of the line capacity can vary significantly, depending on circumstances. During the recovery period from the hurricanes, many lines operated at or beyond their design capacity, while others had low flow rates for periods lasting from several days to more than a week. Several lines had such low flow rates that they were shut down.

In spite of the operational problems, natural gas continued to flow because of the many interconnections that link the pipelines together. Companies used this interconnectivity to flow natural gas around non-operational damaged pipeline sections and pathways, to bypass non-operational plants or compressor stations, and to reroute flow to onshore operating facilities. This was accomplished through a great deal of teamwork and creativity such as reversing flow direction and utilizing bypasses. The interconnectivity of primary pipelines, which was the most important to maintaining gas flow, is greater onshore and declines as one moves away from shore. Onshore interconnects are typically less likely to suffer failure because of hurricane events, and repairs are not as difficult to make as those to offshore pipelines.

Even with the pipeline network flexibility and the cooperative efforts by operators, it was not physically possible or economical to reroute all available Gulf gas production. As a result, the damage sustained by the pipeline network materially reduced production from the Gulf.

Flow rates of primary lines located within the hurricane impact area were stabilizing within normal ranges by early March 2006. At that time, operators were still considering how or whether to repair the remaining damaged facilities. Most of the remaining damage was located near the outer fringes of the lines or at end segments that connect to platforms with low production volumes.

In some cases parties have decided, because of economics, not to repair shared assets (e.g., platforms) that were part of the pipeline infrastructure. This sometimes resulted in a work around, such as laying pipe on the sea floor, to avoid a more costly investment. The return on pipeline investment is recovered through gas flow rather than gas price. Therefore the depletion rates of producing areas are critical factors in the decision to repair, abandon, or expand facilities. Repairs to the secondary pipelines, which affect small portions of overall scheduled capacity for a pipeline, were prioritized based on the availability of work crews and economics (see box, "Factors Affecting Recovery Efforts").

In tracking recovery efforts on a line-by-line basis, DOE considered two events to be significant: (1) a pipeline's return to partial flow, and (2) when a pipeline reached and held a consistent flow rate. DOE also closely monitored a number of factors that could restrict the pipeline from operating at normal capacities and attempted to measure their effects.

Just after the hurricanes, the pipelines had the capability to transport approximately 4.5 Bcf per day, or enough flow capacity to handle all available production from the Gulf at that date. The capacity to flow was maintained by several pipelines, most of which were located outside of the hurricane impact area. Had there been more production available, the pipelines located within the hurricane impact area most likely would not have been able to handle the volume or reroute the flow to onshore facilities. The pipelines at this time were at least a partial constraint in the production and supply chain. By the end of October, many of the primary lines in the hurricane impact area were well on the way to recovery or fully operational. Recovery continued to progress through December, and by January, the recovery had reached a plateau.

As of March 8, 2006, when DOE discontinued its active monitoring of repair efforts, there were still several primary pipelines with damage to sections that cut off production. There was also damage remaining to some secondary pipelines and outlying laterals from both primary and secondary lines. Final repairs to these lines most likely will take several months to complete. Competition is extensive for the crews and equipment needed for making repairs and for extending lines to new producing areas.

Factors Affecting Recovery Efforts

Several factors have affected the return to service of various line segments. The depth of water in which the damage resides, the length of the effected zone, size of the pipeline, and the complexity of the zone (e.g., interconnects, sea valves) are all factors in determining the time, complexity, and costs required to repair or replace damaged areas. There are a limited number of crews that can make repairs in deep water. Initially after the hurricanes, many of these crews were under contract and committed to specific companies, thus affecting repair scheduling. Also, producers sometimes outbid pipeline operators for the services of these specialized crews. Other factors affecting repair schedules included those instances when damages turned out to be more extensive than original assessments revealed, which lengthened the time required to complete repairs. Rough seas at times also contributed to extending the required repair time.

Long lead times required for delivery of repair materials and components also hindered repair efforts. Many components such as valves and flanges must be custom-built or are in short supply. Destroyed or damaged platforms also presented major problems, as connections needed to be isolated and lines dewatered. Pipeline breaches create the need to dewater the line and remove contaminants before operation is restarted. The only facilities for treating large volumes of water from the pipeline are located onshore. This means that the sea water must be routed through the pipe to shore without damaging other sections of the pipeline during the transporting process.

As late as early May, pipeline operators were still revising assessments of damage to some outer-lying pipelines. These assessments, for the most part now complete, have revealed that several pipelines experienced more extensive damage than the original assessments indicated, and many more pipelines were damaged than first reported. On May 1, 2006, MMS reported that, based on additional industry investigations and reports, more than twice the number of pipelines were damaged than had been identified in January (457 vs. 183), and the number of damaged primary lines was upped from 64 to 101.[5] MMS reported that 32 of the damaged primary lines had returned to service.

V. Natural Gas Processing

The natural gas product fed into the mainline gas transportation system in the United States must meet specific quality measures for the pipeline grid to operate properly. Consequently, natural gas produced at the wellhead, which in most cases contains contaminants[6] and natural gas liquids,[7] must be processed, i.e., cleaned, before it can be safely delivered to the high-pressure, long-distance pipelines that transport the product to the consuming public. Natural gas that is not within certain specific gravities, pressures, Btu content range, or water content levels will cause operational problems, pipeline deterioration, or can even cause pipeline rupture.

The processing of wellhead natural gas into pipeline-quality dry natural gas can be quite complex and usually involves several processes to remove: (1) oil; (2) water; (3) elements such as sulfur, helium, and carbon dioxide; and (4) natural gas liquids. In addition to those four processes, it is often necessary to install scrubbers and heaters at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the natural gas does not drop too low and form a hydrate with the water vapor content of the gas stream. These natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes.

Within the 70 counties and parishes located along the Gulf Coast States of Texas, Louisiana, Mississippi, and Alabama, there were 47 major natural gas processing plants (each with a processing capability of 100 million cubic feet (MMcf) per day or greater) when the hurricanes struck. Total processing capacity for the major plants was 22,841 MMcf per day. Of the 47 plants,

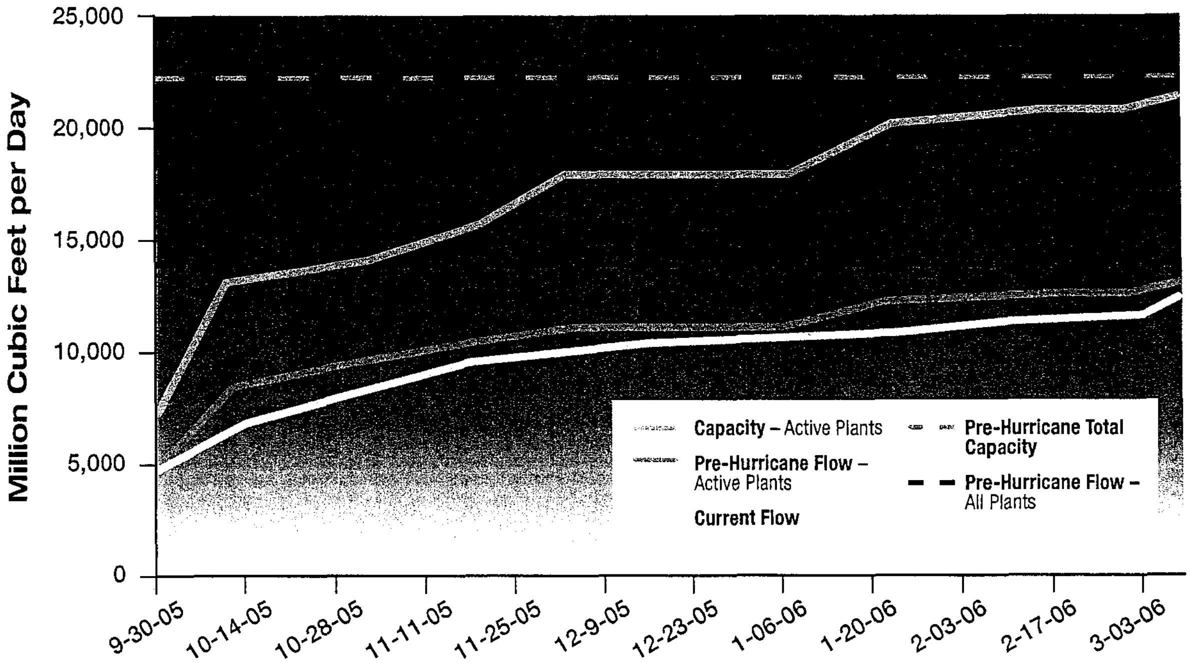


Figure 12. **Capacity and Flow Data for Major Gas Processing Plants in the Coastal Counties Adjacent to the Gulf of Mexico (End of September 2005—Early March 2006)**

9 also included on-site fractionation facilities, that is, they had the capability to extract individual natural gas liquid components including ethane, propane, butane, and pentane, which are sold as separate commodities.

The other 38 natural gas processing plants traditionally confine their operations primarily to extracting pipeline-quality natural gas (residue gas), and secondarily the production of a natural gas liquids mixture stream (often referred to as Y-grade) that is transported to a separate facility for fractionation via rail, truck, barge, or pipeline, mostly the latter.

In the area surveyed, there are at least 17 fractionation sites, the largest being the Mont Belvieu complex, located in southeast Texas about 60 miles from the Louisiana border. More than a dozen pipelines in the Texas-Louisiana area transport Y-grade liquids (a mixed heavy hydrocarbons liquid stream under pressure) to the Mont Belvieu area for fractionation. Conversely, multiple types of transportation infrastructure (pipeline, truck, rail, or barge) are available to move finished NGL products and refinery grade propylene to area markets as feedstock for chemical, refining, and industrial markets. Mont Belvieu and most of the other local fractionation facilities maintain, or have access to, salt cavern facilities which are used for storing unprocessed mixed liquids and individual extracted NGL products.

Natural Gas Processing Plants

Damage Assessment

Although the processing/treatment segment of the natural gas industry generally receives little public attention, its overall importance to the natural gas industry became readily apparent in the aftermath of hurricanes Katrina and Rita in August and September 2005. Damage caused by the hurricanes resulted in a number of shut-ins to gas processing plants.

Causes of the shut-ins varied—based on either internal or external conditions. Internal conditions refer to damage directly affecting the gas processing plants, including flooding, debris, and destruction of equipment. External conditions refer to closures caused by lack of electricity, inaccessibility of the plant site because of road damage or other problems, lack of upstream supplies to the processing plant caused by production shut-ins or pipeline problems, and downstream problems related to the disposal of natural gas liquids or Y-grade liquids.

Downstream conditions are critical to an operating gas processing plant whether the flow from the gas processing plant is raw gas for processing at a fractionator (i.e., the Y-grade liquids) or processed liquids that are ready to be marketed. If the typically large volumes of co-products cannot be properly disposed of, the gas processing plant cannot operate. The liquids problems were caused either by problems affecting the pipelines exiting the gas processing plant or at the downstream facility itself.

After Hurricane Katrina made landfall in late August, there were at least eight gas processing plants known to have been closed down.[8] These eight plants represented 6,615 MMcf per day of capacity that had a pre-hurricane flow of 4,158 MMcf per day. When Hurricane Rita struck the Gulf producing areas less than a month later, the cumulative damage from both storms was much greater.

At the end of September 2005, 27 gas processing plants with 16,796 MMcf per day of capacity were shut in, or almost 75 percent of total capacity for all major plants in the region (Figure 12).[9] The 27 shut-in gas processing plants included virtually all the large plants in the area from Galveston Bay, Texas, through Mississippi (Figure 13). Only 20 of the major plants, with a capacity of 6,045 MMcf per day, were active at the end of September.

Eleven of the twenty-seven plants were inactive because of internal factors, which forced the shut-in of 7,665 Bcf per day of capacity. Most of the facilities with internal

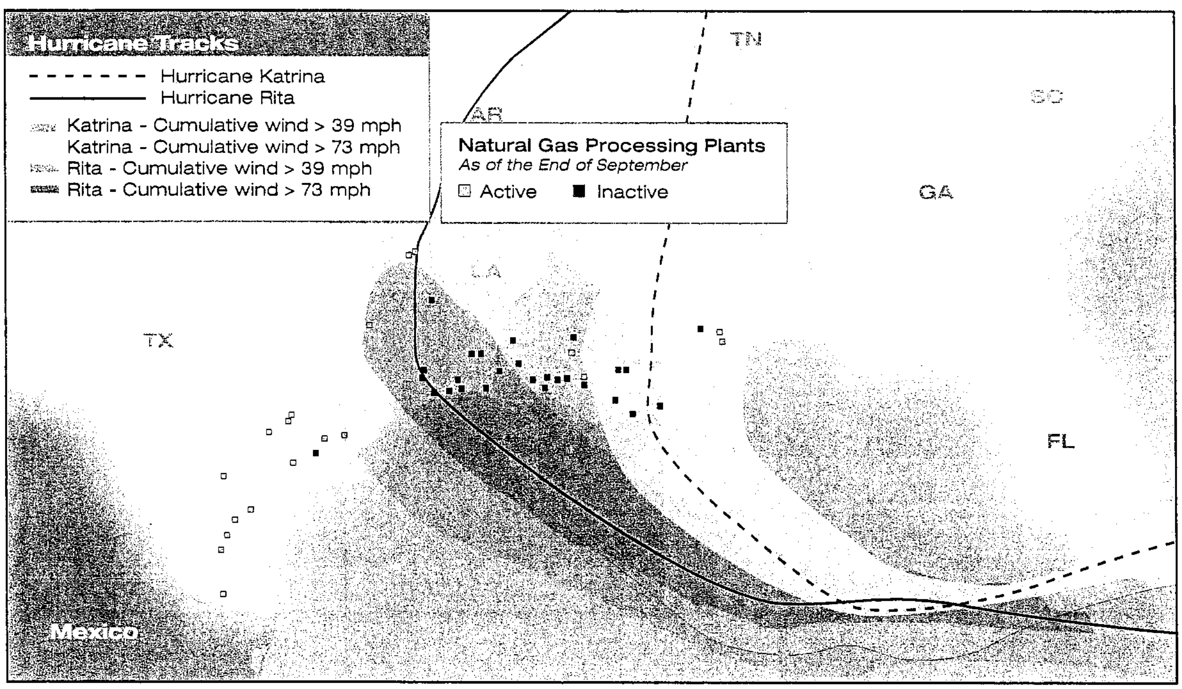


Figure 13. Gulf Processing Plants Affected by Hurricane Katrina or Hurricane Rita

problems appear to have endured some amount of flooding from either storm surge or rain penetration. The reports on water damage did not necessarily include a clear designation regarding the nature of the problem. A number of facilities were flooded so badly that inspections were not conducted or completed for weeks. The major internal problems were debris and damage to equipment, especially controls and electrical equipment. There were few reported problems involving damage to moving equipment or structures.

In addition to the shut-in capacity as a result of internal problems, an even larger amount of capacity was offline although the plants themselves were reported as operational. At the end of September 2005, there were 16 gas processing plants that were reported as operational but were not active because of problems outside the plant. Causes for these 16 shut-ins included: lack of power (6 plants), upstream supplies being unavailable (10 plants), problems with disposal of co-products downstream (6 plants), and one case of bypass because of market conditions.[10]

Recovery

As a group, the plants affected by external problems were reactivated most quickly, with roughly two-thirds of those being back on-line by the end of October 2005. The plants with internal problems required the longest recovery periods. Only one plant with internal problems became active again during October, and even at the end of December, 7 of the original 11 remained inactive.

Recovery during October 2005 was the most active of any month after the hurricanes in terms of the number of plants returned to service, as the number of inactive plants declined from 27 at the end of September to 15 by the end of October. At the end of October, 8,335 MMcf per day of capacity was inactive, with 14,506 MMcf per day active (Figure 12).

Almost half the remaining inactive gas processing plants returned to operation during November, as the count fell from 15 to 8 by the end of the month. Seven gas processing plants were inactive because of internal problems. By the end of November, there were 39 active plants with capacity of 17,366 MMcf per day and inactive capacity of 5,475 MMcf per day. The situation was unchanged at the end of the calendar year as no additional plants were activated during December, although flows through the active plants did increase.

In January, four more plants with a capacity of 2,425 MMcf per day were restored back to active status. By the end of January, four gas processing plants were still inactive. Included in the group of four was BP's Grand Chenier plant with capacity of 950 MMcf per day, which was being decommissioned as announced in late January. As of March 8, 2006, 45 of the 47 plants were restored to active status. The final reactivation of a major processing plant occurred on April 2, 2006, when the Stingray plant resumed processing, bringing capacity of all major active plants to 21,891 MMcf per day.

Natural Gas Fractionators (Natural Gas Liquids Plants)

Damage Assessment and Recovery

Fractionators in Texas

While the path of Hurricane Katrina did not take it anywhere near the Mont Belvieu complex in east Texas, this area was within the edge of Hurricane Rita's path. Most of the fractionation, storage, and pipeline facilities in the area reported no sustainable major damage. However, the absence of water, which could not be pumped to three of the plants because the local electric power grid was down, did force temporary closures. (All plants in the Mont Belvieu area went into a planned shutdown mode prior to the expected hurricane landfall.)

One fractionator, which had its own on-site well water source, was able to return to operations within a day or so. The other three facilities at Mont Belvieu did not reopen for about 8 days. Some flows were directed to area storage facilities that were still operational.

There was an indirect impact from the storm on parts of the area's pipeline network. Although a number of pipelines suffered no major damage themselves, a lack of electric utility service and/or damage to power facilities at pump stations along the pipeline system caused a temporary shutdown of operations.

Other fractionators are located in the Beaumont area of east Texas (Jefferson County), where certain facilities were significantly impacted by Hurricane Rita. Response to the damage to the fractionators varied. In mid-October, Y-grade deliveries from some gas processing plants in the area were redirected to Mont Belvieu for fractionation or into temporary storage. In at least one case where both gas processing and refinery facilities were damaged, recovery of refinery operations was given priority. Consequently, the repairs to the fractionator facility were not completed until late November. Today all fractionation and refinery operations are back to normal.

Fractionators in Louisiana

The hurricanes caused numerous difficulties for several fractionators in southern Louisiana. A number of fractionators suspended operations at least temporarily because of up- or down-stream problems. Upstream problems included shut-in offshore production, pipeline damage, or loss of supply flow because of inactive gas processing plants.

Fractionators also were affected if the downstream pipelines or storage were unavailable or customers were unable to receive the NGLs. These difficulties then might result in other bottlenecks. For example, in the aftermath of the hurricanes, operations on certain pipelines were disrupted at least briefly, with the result that natural gas processing plants that used these lines for transportation of their raw NGL mixture had to cease gas processing operations because of a lack of liquids storage facilities.

V. LNG

Liquefied natural gas (LNG) plays an important role in diversifying and expanding natural gas supplies. LNG arriving in the continental United States enters through one of five LNG receiving and regasification terminals located along the Atlantic and Gulf coasts. The United States currently has six LNG terminals that receive, store, and regasify LNG—four on the mainland, one in the offshore Gulf of Mexico, and one in Puerto Rico.

Damage Assessment

The Panhandle Energy/Trunkline LNG terminal in Lake Charles, Louisiana, and the Excelerate Energy sub-sea Gulf Gateway Energy Bridge 116 miles off the Louisiana coast were in the paths of hurricanes Katrina and Rita. Assessments indicate the hurricanes had only minor impacts on these two LNG import terminals. The Lake Charles terminal has the capacity to import 1.5 billion cubic feet (Bcf) of gas per day and received 103.8 Bcf in 2005. The Gulf Gateway Energy Bridge facility has the capability to import 0.5 Bcf per day.

The Lake Charles terminal is connected to the Gulf of Mexico by a 48-mile (80 km) ship channel. The channel is dredged to a depth of 40 feet (12 m) and is 400 feet (120 m) wide with no overhead navigational obstructions. The facility is connected to the mainline transmission system of Trunkline Gas Company, LLC by 45 miles (72 km) of 30-inch diameter pipeline with a capacity of 1.2 Bcf per day (9.1 mmtpa).

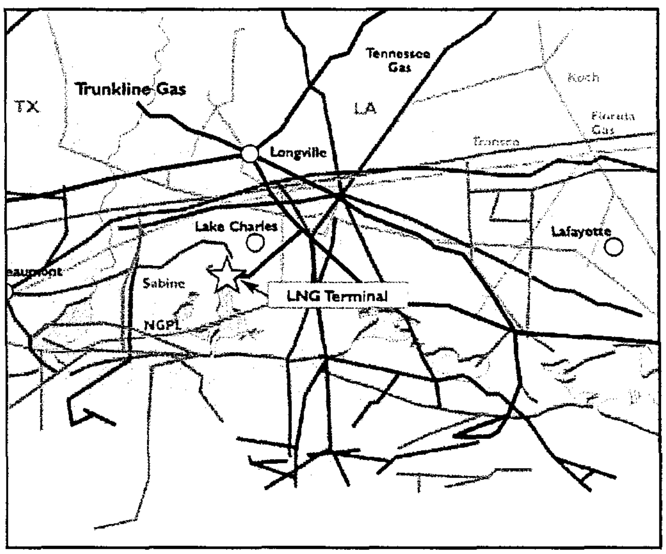


Figure 14 Lake Charles LNG Terminal and Surrounding Pipelines

From September 26 to October 3, 2005, the Lake Charles navigation channel and turning basin were closed because of debris in the waterway and dockage area that required removal. In addition there was limited operational capability to transfer LNG from tanker to storage because of the lack of commercial electric power.

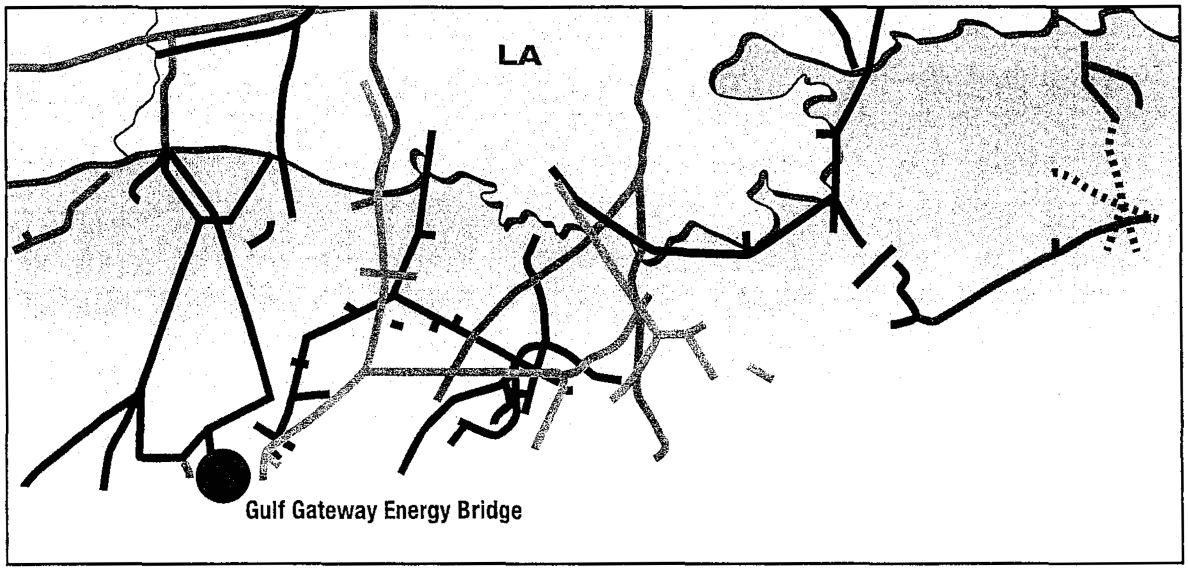


Figure 15. Gulf Gateway Energy Bridge and Surrounding Pipelines

On October 3, 2005, the navigational channel and turning basin reopened to deep draft marine traffic for daylight transits. However, the Trunkline LNG terminal was operating on backup generator power thereby limiting cargo transfers and regasification rates below normal operating inventories. The terminal's LNG inventory increased to 70 percent of capacity (4.4 Bcf) upon completion of cargo transfer from LNG tank ships. On October 5, 2005, the Trunkline LNG terminal at Lake Charles was operational at the pre-hurricane normal levels. Full commercial power was restored. Full regasification and send-out capability and LNG cargo transfers were completed in evening hours.

LNG operations at Excelerate Energy's Gulf Gateway Energy Bridge deepwater port were also affected by the paths of both Katrina and Rita. However, the initial diving assessment results indicated little or no damage was done to the facility. Gas gathering pipelines Sea Robin and Blue Water, which service the Gulf Gateway terminal, were impacted by the hurricanes and the pipelines were in-operative through mid-November. The Gulf Gateway facility is operational; however no shipments had been scheduled because of the unavailability of spot market cargos.

VI. Information Collection

Natural Gas Production Information Collection

The primary source of natural gas production data for the Federal Outer Continental Shelf (OCS) in the Gulf of Mexico is the Department of the Interior's Minerals Management Service (MMS),[11] which has oversight and regulatory responsibility for petroleum operations on the Federal OCS. As part of its normal operations, MMS collects monthly production information for all natural gas wells operating on platforms in the Federal OCS. This information is stored in MMS's Technical Information Management System (TIMS). It is made available to the public on a monthly basis on the MMS website, although data are only available 2 to 3 months after the month in question.

In response to the damage inflicted by the hurricanes, MMS conducted an emergency data collection effort to provide more detailed and real-time information on the impacts of the hurricanes on Federal OCS Gulf production. Here, MMS used TIMS data plus direct contact with operators of the natural gas wells and platforms to assess: numbers of platforms damaged or destroyed, shut-in production, pipeline segments that have facility measuring points (FMPs), and daily volumes at FMPs.[12] With this emergency data collection effort MMS was able to issue a daily report on how much natural gas production was shut in for the Gulf in aggregate.

Natural Gas Pipeline Information Collection

The Federal Energy Regulatory Commission (FERC) requires that natural gas interstate pipeline companies provide complete and timely information about available and released transportation capacity on user-friendly, Internet accessible informational listings that are accessible by all customers on an equal basis. These web-based electronic information profiles provide a wealth of information, including the Daily Scheduled Capacity and Available Capacity on a receipt and delivery point basis listed as Operationally Available by Segment or by Location. The listings also contain Total Design Capacity for each point.

Natural Gas Processing Plant Information Collection

Information on a limited number of data items is sufficient to represent the condition of the processing plant segment of the industry. There is no public source of information regarding plant status and operations that is available on a timely basis. After the hurricanes, information on the larger processing plants was provided by industry sources.

VIII. ENDNOTES

1. Most of the information in this report is compiled through March 8, 2006, with few exceptions. A key exception concerns the final reactivation of gas processing plants which occurred with the startup of the Stingray plant on April 2, 2006, bringing the count of active plants to 46. As noted in the section on gas processing plants, the Grand Chenier plant was decommissioned so it will not be reactivated.

2. The Gulf of Mexico region in this section refers to the Federal Outer Continental Shelf (OCS) in the Gulf of Mexico, which is under the jurisdiction of the U.S. Department of the Interior, Minerals Management Service. The Federal Government administers the submerged lands, subsoil, and seabed, lying between the seaward extent of the States' jurisdiction and the seaward extent of Federal jurisdiction. State jurisdiction extends 3 nautical miles (3.3 miles) off the coastline, excepting Louisiana where it extends 3 imperial nautical miles (3.45 miles), and Texas and the west coast of Florida where jurisdiction extends 9 nautical miles.

   Federal jurisdiction is defined under accepted principles of international law. The seaward limit is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured or, if the continental shelf can be shown to exceed 200 nautical miles, a distance not greater than a line 100 nautical miles from the 2,500-meter isobath or a line 350 nautical miles from the baseline. Outer Continental Shelf limits greater than 200 nautical miles but less than either the 2,500 meter isobath plus 100 nautical miles or 350 nautical miles are defined by a line 60 nautical miles seaward of the foot of the continental slope or by a line seaward of the foot of the continental slope connecting points where the sediment thickness divided by the distance to the foot of the slope equals 0.01, whichever is farthest.

3. Minerals Management Service, Press Release: "Impact Assessment of Offshore Facilities from Hurricanes Katrina and Rita," January 19, 2006.

4. Minerals Management Service, Press Release: "Office of the Secretary, Interior Secretary Gale Norton Reports on Gulf of Mexico Energy Status," October 4, 2005.

5. Minerals Management Service, Press Release: "MMS Updates Hurricanes Katrina and Rita Damage," May 1, 2006.

6. Includes non-hydrocarbon gases such as water vapor, carbon dioxide, hydrogen sulfide, nitrogen, oxygen, and helium.

7. Ethane, propane, and butane are the primary heavy hydrocarbons (liquids) extracted at a natural gas processing plant, but other petroleum gases, such as isobutane, pentanes, and normal gasoline, also may be processed.

8. This information is as of September 19, 2005. It is based on reports by the Minerals Management Service, staff reports from the DOE Office of Fossil Energy, data compiled by the Energy Information Administration, and trade press reports.

9. Many of the gas processing plants ceased operations in advance of the hurricanes for safety reasons. Those plants that were unaffected by the storm opened promptly thereafter.

10. Some plants were confronted with more than one problem, so the sum of the plants exceeds the total.

11. Department of the Interior, Minerals Management Service (MMS), Minerals Revenue Management, Royalty-In-Kind Program, and Offshore Mineral Management, Production and Development, Structural & Technical Support, Surface Commingling & Production Measurement, and Pipeline Section.

12. When events occur in the Gulf of Mexico region, MMS Continuity of Operations Plan (COOP) requires natural gas companies to report evacuated rigs and platforms and shut-in oil (BOPD) and natural gas (MMcf/d) volumes. The data are required to be reported by 11:30 CST and a daily report, aggregated by districts, is posted on the MMS website (www.mms.gov) at 13:00 CST.

JULY 2006

SOUTHEAST SUPPLY HEADER PROJECT

Docket No. CP07-_____-000

EXHIBIT P

SESH Rate Derivation and *Pro Forma* Tariff

Rates and Tariff

Table of Contents

Explanatory Notes

Rate Derivation

SESH has calculated its maximum rates for FTS firm transportation service as shown on Schedule 2 of this Exhibit P. SESH's maximum rates were developed, using the Commission's SFV methodology.

The cost of service which SESH used for developing the FTS firm reservation rate was its total fixed cost of service, less $1,500,000 which was assigned to interruptible service. The resulting FTS reservation cost of service was divided by a volume determinant equal to SESH's total capacity of 1,032,951 dth per day, times 12 months, as shown on lines 13–17 of Schedule 2.

The usage rate for FTS service was developed by dividing SESH's variable cost of service by a design determinate equal to SESH's total capacity of 1,032,951 dth per day, times 365 days, times a 70% load factor. This calculation is shown on lines 18-21 of Schedule 2.

The FTS usage-2 rate was set equal to the 100% load factor rate for firm FTS service.

The usage rates for interruptible ITS and PALS services were set to equal the 100% load factor FTS rate.

Explanatory Notes

Cost of Service

SESH's cost of service is based on its total capital cost as presented in Exhibit K herein. It proposes to use a 1.67% depreciation rate as described in Exhibit O.

SESH's proposed 10.0% rate of return was calculated on schedule 7 of this Exhibit P, based on the company's proposed 50%/50% capital structure. A debt cost of 6.5% was applied, as described in Exhibit L-1 herein.

A return on equity of 13.5% is being requested, based on SESH's level of business and financial risk. The Commission has recently approved returns on equity at the 14% level for new startup pipeline projects similar to SESH. The Gulfstream Natural Gas System, L.L.C. received authority to use a 14% ROE rate, in its initial rates, in a Commission order issued April 28, 2000 in Docket No. CP00-6-000 (91 FERC 61,119).

Income taxes have been included in SESH's cost of service, consistent with the Commission's policy statement in Docket No. PL05-005 [1]. Under that policy statement, partnerships are permitted recovery of income taxes in cost of service, to the extent of their ownership by tax paying corporations. Both of the SESH partners are ultimately owned by tax paying corporations. Income taxes have been calculated as shown on schedule 6, using a 35% federal income tax rate and a 6% state income tax rate.

Ad valorem taxes were developed, as shown on schedule 4, by applying separate ad valorem factors to the gross plant balances in each state. The factors were developed based on the individual assessment ratios and tax rates in each county.

An estimate of operation and maintenance was included based on an engineering estimate of direct operation and maintenance expenses for similar facilities of SESH's operating partner Duke Energy Gas Transmission, LLC. Additional administrative and general expenses have been included based on forecasted overhead costs for the partnership.

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[1] Inquiry Regarding Income Tax Allowances, Docket No. PL05-5-000 (111 FERC ¶61,139)

Explanatory Notes

SESH Tariff

Included in Exhibit P hereto is the *pro forma* FERC Gas Tariff whereby SESH will provide transportation service. The terms and conditions of the tariff are structured to conform to the requirements of the Commission's Order Nos. 636, *et seq.* and Order No. 637. The tariff includes the proposed Rate Schedule FTS, under which SESH will render firm transportation service to the SESH Customers and the proposed Rate Schedule ITS, under which SESH will render interruptible transportation service. The tariff also provides for the ability to negotiate rates.

Docket No. CP07-___
Exhibit P
Schedule 2

Southeast Supply Header, LLC
Total Cost of Service and Rate Design

Line No.	(1) Description	(2) 2008	(3) 2009	(4) 2010
1	Operation and Maintenance Expense	$11,283,791	$11,735,143	$12,204,548
2	Depreciation Expense	$13,025,015	$13,025,015	$13,025,015
3	Taxes Other than Income	$9,920,856	$10,123,794	$10,330,971
4	Federal Income Taxes	$28,365,188	$27,303,413	$26,053,490
5	State Income Taxes	$5,172,983	$4,979,346	$4,751,396
6	Return	$77,307,805	$74,386,519	$70,947,579
7	Total Cost of Service	$145,075,638	$141,553,230	$137,312,999
8	Cost of Service Breakdown For Rate Design			
9	Fixed Cost of Service For FTS	$141,877,264		
10	Cost of Service Allocation to Interruptible	$1,500,000		
11	Variable Cost of Service	$1,698,374		
12	Total	$145,075,638		
13	FTS Reservation Rate			
14	Fixed Cost of Service For FTS	$141,877,264		
15	Capacity (dth/d)	1,032,951		
16	Design Determinant	12,395,412		
17	Reservation Rate ($/dth)	$11.446		
18	FTS Usage Rate			
19	Variable Cost of Service	$1,698,374		
20	Design Determinant (ln 15 x 365 x 70%)	263,918,981		
21	Usage Rate ($/dth)	$0.0064		
22	FTS Usage-2 Rate	$0.3827		
23	ITS Usage Rate ($/dth)	$0.3827		
24	PALS Usage Rate ($/dth)	$0.3827		

Docket No. CP07-___
Exhibit P
Schedule 3

Southeast Supply Header, LLC
Operation and Maintenance Expenses

Line No.	(1) Description	(2) 2008	(3) 2009	(4) 2010
1	Direct O&M			
2	Compressor Station -Labor	$1,323,660	$1,376,607	$1,431,671
3	Compressor Station -M&O	$1,698,374	$1,766,309	$1,836,961
4	Pipeline -Labor	$1,463,186	$1,521,713	$1,582,582
5	Pipeline -M&O	$1,877,397	$1,952,493	$2,030,593
6	M&R Station -Labor	$31,851	$33,125	$34,450
7	M&R Station -M&O	$40,868	$42,503	$44,203
8	Total Direct O&M	$6,435,336	$6,692,749	$6,960,459
9	Administrative and General	$4,848,455	$5,042,393	$5,244,089
10	Total O&M	$11,283,791	$11,735,143	$12,204,548

Docket No. CP07-___
Exhibit P
Schedule 4

Southeast Supply Header, LLC
Depreciation Expense and Other Taxes

Line No.	(1) Description		(2) 2008	(3) 2009	(4) 2010
1	Depreciation Expense				
2	Depreciable Plant		$779,941,000	$779,941,000	$779,941,000
3	Depreciation Rate		1.67%	1.67%	1.67%
4	Depreciation Exp.		$13,025,015	$13,025,015	$13,025,015
5	Taxes Other than Income:				
6	Gross Plant				
7	Louisiana		$131,487,841	$131,487,841	$131,487,841
8	Mississippi		$568,029,707	$568,029,707	$568,029,707
9	Alabama		$82,488,452	$82,488,452	$82,488,452
	Total Gross Plant		$782,006,000	$782,006,000	$782,006,000
10	Ad Valorem Taxes				
11	Louisiana	2.37%	$3,121,137	$3,183,560	$3,247,231
12	Mississippi	0.95%	$5,373,477	$5,480,946	$5,590,565
13	Alabama	1.46%	$1,200,207	$1,224,211	$1,248,695
14	Total Ad Valorem Taxes		$9,694,821	$9,888,717	$10,086,492
15	Payroll Taxes				
16	Labor Cost		$2,818,697	$2,931,445	$3,048,703
17	Payroll Taxes	8.02%	$226,035	$235,076	$244,479
18	Total Taxes Other than Income		$9,920,856	$10,123,794	$10,330,971

Docket No. CP07-___
Exhibit P
Schedule 5

Southeast Supply Header, LLC
Rate Base and Return

Line No.	(1) Description		(2) 2008	(3) 2009	(4) 2010
1	Rate Base				
2	Gas Plant in Service		$782,006,000	$782,006,000	$782,006,000
3	Accumulated Depreciation		($6,512,508)	($19,537,523)	($32,562,538)
4	Net Plant		$775,493,492	$762,468,477	$749,443,462
5	Working Capital				
6	Materials & Supplies @	0.313%	$2,443,970	$2,541,729	$2,643,398
7	Accum. Deferred Income Taxes		($4,859,413)	($21,145,012)	($42,611,066)
8	Total Rate Base		$773,078,050	$743,865,194	$709,475,795
9	Return @	10.00%	$77,307,805	$74,386,519	$70,947,579

Docket No. CP07-___
Exhibit P
Schedule 6

Southeast Supply Header, LLC
Federal and State Income Taxes

Line No.	(1) Description		(2) 2008	(3) 2009	(4) 2010
1	Return		$77,307,805	$74,386,519	$70,947,579
2	Adjustments				
3	Interest and Debt Expense		($25,125,037)	($24,175,619)	($23,057,963)
4	Amortization of Equity AFUDC		$495,438	$495,438	$495,438
5	Total Adjustments		($24,629,599)	($23,680,181)	($22,562,525)
6	Net Taxable Income		$52,678,206	$50,706,338	$48,385,054
7	Federal Income Tax @	35.00%	$28,365,188	$27,303,413	$26,053,490
8	Pre-FIT (Lines 6 and 7)		$81,043,394	$78,009,751	$74,438,544
9	State Income Tax @	6.00%	$5,172,983	$4,979,346	$4,751,396

Docket No. CP07-___
Exhibit P
Schedule 7

Southeast Supply Header, LLC
Rate of Return

Line No.	(1) Description	(2) Capitalization Ratios	(3) Component Cost	(4) Return Component
1	Long-Term Debt	50.00%	6.50%	3.250%
2	Equity	50.00%	13.50%	6.750%
3	Total	100.00%		10.000%

FERC GAS TARIFF

PRO FORMA ORIGINAL VOLUME NO. 1

OF

SOUTHEAST SUPPLY HEADER, LLC

FILED WITH

FEDERAL ENERGY REGULATORY COMMISSION

Communications Concerning the Tariff Should
Be Addressed To:

5400 Westheimer Court
Houston, TX 77056

Telephone Number:
Facsimile Number:

TABLE OF CONTENTS

PRELIMINARY STATEMENT

Southeast Supply Header, LLC ("SESH") owns and operates a natural gas pipeline company engaged in the business of transporting natural gas in interstate commerce under authorization granted by, and subject to the jurisdiction of, the Federal Energy Regulatory Commission. Its pipeline system extends in an easterly direction from the Perryville Hub, Louisiana to various points in Mississippi and Alabama terminating at an interconnection with Gulfstream Natural Gas System, L.L.C. near Coden, Alabama.

The location of SESH's system is shown on the map included herein.

Services will be provided under specific Agreements and rate schedules and SESH reserves the right to limit its Agreements for transportation of gas to Shippers acceptable to it after consideration of its existing commitments, delivery capacity, Delivery Point, credit-worthiness of Shippers, and other factors deemed pertinent by SESH, consistent with the terms and conditions of this tariff.

Nothing in this tariff is intended to inhibit the development of, or discriminate against the use of, imbalance management services provided by third parties or SESH's Shippers. Any party interested in providing imbalance management services must coordinate with SESH.

System Map

(A System Map reflecting the pipeline route as constructed will be set forth on this tariff sheet.)

STATEMENT OF RATES FOR TRANSPORTATION OF NATURAL GAS

Rate Schedule	Maximum Rate Per Dth	Minimum Rate Per Dth
RATE SCHEDULE FTS 1/		
1. Reservation Rate Per Month Per Dth of MDQ	$11.446	$ 0.0000
2. Usage-1 Rate Per Dth	$ 0.0064	$ 0.0064
3. 100% L.F. Rate	$ 0.3827	$ 0.0064
4. Usage-2 Rate Per Dth	$ 0.3827	
RATE SCHEDULE ITS 1/		
1. Usage-1 Rate Per Dth	$ 0.3827	$ 0.0064
2. Usage-2 Rate Per Dth	$ 0.3827	
RATE SCHEDULE PALS 1/		
1. Usage Rate Per Dth	$ 0.3827	$ 0.0064

1/ Backhaul rate is equal to the Forward haul rate.

STATEMENT OF RATES FOR TRANSPORTATION OF NATURAL GAS

Rate Schedule	Maximum Rate Per Dth	Minimum Rate Per Dth
MAXIMUM DAILY CAPACITY RELEASE RATE 1/		
1. Reservation Rate Per Month Per Dth of MDQ	$ 0.3763	$ 0.0000
2. Usage-1 Rate per Dth	$ 0.0064	$ 0.0064
3. 100% L.F. Rate	$ 0.3827	$ 0.0064

1/ Backhaul rate is equal to the Forward haul rate.

STATEMENT OF RATES FOR TRANSPORTATION OF NATURAL GAS

ADDITIONAL CHARGES OR SURCHARGES APPLICABLE TO FTS AND ITS SERVICE	Maximum Rate Per Dth	Minimum Rate Per Dth
1. Annual Charge Adj. (ACA)	$ 0.0000	$ 0.0000
2. Gas for Transporter's Use (%) 1/	0.70 Percent	

1/ Transporter's Use (%) will not be applied to Backhaul Transportation.

STATEMENT OF NEGOTIATED RATES FOR TRANSPORTATION OF NATURAL GAS

RATE SCHEDULE FTS
Firm Transportation Service

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the Transportation of Gas by Transporter, subject to the following limitations:

(a) Transporter has determined that it has sufficient available and uncommitted capacity to perform service requested by Shipper; and

(b) Shipper and Transporter have executed an Agreement under this Rate Schedule.

2. APPLICABILITY AND CHARACTER OF SERVICE

(a) This Rate Schedule shall apply to all Transportation Service rendered by Transporter for Shipper pursuant to the executed Agreement under this Rate Schedule.

(b) Transportation Service under this Rate Schedule shall consist of: (1) the receipt of Gas on behalf of Shipper, (2) the Transportation of Gas, and (3) the Tender of Gas for delivery by Transporter to Shipper, or for Shipper's account up to Shipper's MDQ.

(c) Transportation Service rendered under this Rate Schedule shall be firm, up to the Transportation Path MDQ specified in the executed Agreement.

RATE SCHEDULE FTS
Firm Transportation Service
(CONTINUED)

3. RATES

Each Month, Shipper shall pay to Transporter the following rates:

3.1 Reservation Rates.

(a) A Reservation Rate, as stated in the Statement of Rates for Transportation of Natural Gas, shall be paid each Month for each Dekatherm of Shipper's MDQ.

3.2 Usage Rates.

(a) The Usage-1 Rate, as stated in the Statement of Rates for Transportation of Natural Gas, multiplied by that portion of the total quantity of Gas deliveries on any Day pursuant to the Shipper's Agreement which is not in excess of the lower of (i) 110% of the scheduled quantities of Gas under the Agreement for such Day or (ii) the MDQ in effect under the Agreement for such Day.

(b) The Usage-2 Rate, as stated in the Statement of Rates for Transportation of Natural Gas, multiplied by that portion of the total quantity of Gas deliveries on any Day pursuant to the Shipper's Agreement which is greater than the lower of 110% of (i) the scheduled quantities of Gas under the Agreement for such Day or (ii) the MDQ in effect under the Agreement for such Day.

(c) Other Applicable Charges or Surcharges. All applicable surcharges or charges, including, but not limited to those contained in Sections 8 and 22 of the General Terms and Conditions, and as stated in the Statement of Rates for Transportation of Natural Gas multiplied by each Dekatherm of Gas delivered.

RATE SCHEDULE FTS
Firm Transportation Service
(CONTINUED)

3.3 Transporter's Use. Each Shipper will furnish Transporter fuel at the nominated Receipt Point(s). The amount of fuel furnished to Transporter will be based on the applicable percentage for Transporter's Use, as calculated pursuant to Section 22.2 of the General Terms and Conditions and as stated in the Statement of Rates for Transportation of Natural Gas.

3.4 Negotiated Rates. Shipper and Transporter may mutually agree, pursuant to the provisions of Section 30 of the General Terms and Conditions, to a negotiated rate, which rate shall be less than, equal to, or greater than Transporter's Maximum Recourse Rate, but shall not be less than the minimum rate. Any such rates may be based upon a rate design other than straight fixed variable (SFV). Such negotiated rate shall be set forth in an executed Agreement and/or in Transporter's Tariff and shall be agreed to in a written agreement between Transporter and Shipper.

3.5 Discounted Rates. Subject to any limitations agreed to by Shipper and Transporter, Transporter may from time to time and at any time selectively adjust any or all of the rates charged to any individual Shipper for any and all of the transportation paths for which a Maximum Rate and Minimum Rate are stated in the Statement of Rates for Transportation of Natural Gas of this Tariff or a superseding Tariff; provided, however, that such adjusted rate(s) shall not exceed the applicable Maximum Rate(s), nor shall they be less than the Minimum Rate(s), set forth on such sheets. Transporter shall have the right to charge the Maximum Rate at any time as a condition for new service, or for continuation of service under an existing Agreement. Transporter shall make all information filings and/or postings on LINK® as required by the Commission's regulations with respect to any charges at less than the Maximum Rate.

RATE SCHEDULE FTS
Firm Transportation Service
(CONTINUED)

3.6 Failure to Deliver. If on any Day in a Month, due to an event of Force Majeure, Transporter is unable to tender for delivery Transportation volumes, up to Shipper's MDQ scheduled pursuant to Section 6 of the General Terms and Conditions, Transporter shall calculate a credit for such Day to be included in Shipper's invoice for that Month; provided, however, Transporter shall not be obligated to credit Shipper's invoice when Transporter's failure to deliver occurs within (3) three days following a Force Majeure event.

For Shippers paying Recourse Rates, such credit shall be the product of the 100% LF reservation-based portion of the rate stated in the Statement of Rates for Transportation of Natural Gas and the difference between the quantity of Gas scheduled for Transportation Service, up to the MDQ and the quantity actually delivered by Transporter for the account of Shipper during such Day. For Shippers paying less than the maximum rate, the amount of the adjustment, if any, shall be consistent with the discount agreement between Shipper and Transporter. For Shippers paying Negotiated Rates, unless otherwise agreed to in the Negotiated Rate Agreement, such credit shall be the product of (1) the 100% LF reservation-based portion of the applicable Negotiated Rate in effect for the period of non-delivery, and (2) the difference between the quantity of Gas scheduled for Transportation Service up to the MDQ and the quantity actually delivered by Transporter for the account of Shipper during such Day.

RATE SCHEDULE FTS
Firm Transportation Service
(CONTINUED)

4. RECEIPT AND DELIVERY POINTS

4.1 Receipt Point Availability.

(a) Subject to the availability of capacity at any specific point and to the Receipt Point MDQs that apply to Agreements under this Rate Schedule that were executed by Transporter and Shipper on or before December 29, 2006, Shipper shall have access to all Receipt Points on Transporter's system on a Priority Class One basis. Transporter, subject to all necessary regulatory approvals and agreements with interconnecting parties, intends to establish receipt point interconnects with the following interstate pipelines at locations proximate to Transporter's system: CenterPoint Energy Gas Transmission Company's ("CEGT") Carthage to Perryville system ("CEGT-Line CP"); CEGT's Line FM 63 ("CEGT FM 63"); Columbia Gulf Gas Transmission ("Columbia Gulf"); Florida Gas Transmission Company ("FGT"); Gulfstream Natural Gas System, L.L.C. ("Gulfstream"); Gulf South Pipeline Company, L.P. ("Gulf South"); Southern Natural Gas Company ("Sonat"); Tennessee Gas Pipeline Company ("Tennessee"); Texas Eastern Transmission, LP ("Texas Eastern"); and Transcontinental Gas Pipe Line Corporation ("Transco").

(b) The following shall apply only with respect to Agreements under this Rate Schedule that were executed by Transporter and Shipper on or before December 29, 2006:

The Receipt Point MDQ at each of the following Receipt Points shall be equal to the MDQ specified in the applicable Agreement: (i) CEGT-Line CP; (ii) Gulf South's (East Texas Expansion) pipeline; (iii) Columbia Gulf's system near Perryville, Louisiana (subject to completion of the interconnection between Transporter's system and Columbia Gulf's system) and (iv) the proposed Continental Connector pipeline sponsored by a subsidiary of El Paso Corporation, if such

RATE SCHEDULE FTS
Firm Transportation Service
(CONTINUED)

pipeline is constructed and connected with Transporter's system within five (5) years after the date on which service is first initiated on Transporter's system.

4.2 Shipper's Primary Delivery Point(s) and/or Shipper's Transportation Path will be listed in Exhibit B attached to Shipper's Agreement. Shipper shall have the right to utilize all other Delivery Point(s) as Secondary Delivery Point(s), subject to available capacity and the provisions of the General Terms and Conditions.

4.3 Upon five (5) Business Days prior notice, Shipper shall have the right to redesignate any points listed on Exhibit Bas Primary Delivery Point(s), subject to available capacity and the provisions of the General Terms and Conditions; provided, however, if Shipper is paying a Negotiated Rate for service under the Agreement and requests to change its Primary Delivery Point under the Agreement, then unless otherwise agreed to in writing by Shipper and Transporter the rate applicable for service to such new Primary Delivery Point shall be the maximum Recourse Rate. Furthermore, Shipper shall have the right to utilize all other Delivery Point(s) as Secondary Delivery Point(s), subject to available capacity and the provisions of the General Terms and Conditions.

4.4 Subject to mutual agreement and the provisions of Section 12 of the General Terms and Conditions, Shipper shall agree with Transporter as to the minimum delivery pressure at the Delivery Point. Such pressure shall be set forth in Exhibit Bto the Agreement.

5. COMMISSION AND OTHER REGULATORY FEES

Shippers will reimburse Transporter for any separately stated fees required by the Commission or any other federal or state regulatory body.

6. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions of this Tariff are specifically incorporated into this Rate Schedule.

RATE SCHEDULE ITS
Interruptible Transportation Service

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the Transportation of Gas by Transporter when Shipper and Transporter have executed an Agreement under this Rate Schedule.

2. APPLICABILITY AND CHARACTER OF SERVICE

(a) This Rate Schedule shall apply to all Transportation Service rendered by Transporter for Shipper pursuant to the executed Agreement under this Rate Schedule.

(b) Transportation Service under this Rate Schedule shall consist of: (1) the receipt of Gas on behalf of Shipper, (2) the Transportation of Gas, and (3) the Tender of Gas for delivery by Transporter to Shipper, or for Shipper's account.

(c) Transportation Service rendered under this Rate Schedule shall be interruptible. Interruptible service shall be available only to the extent of available capacity as it may be from Day to Day and from time to time within the Gas Day, under current conditions and shall be offered in accordance with the priorities established in the General Terms and Conditions of Transporter's Tariff.

3. RATES

Each Month, Shipper will pay Transporter the following rates:

3.1 Usage-1 Rate. A rate equal to the applicable Usage Rates either as stated in the Statement of Rates for Transportation of Natural Gas multiplied by each Dekatherm of Gas delivered or as agreed upon in writing between Transporter and Shipper, but in no event will such rate be less than the minimum rate as stated in the Statement of Rates for Transportation of Natural Gas.

3.2 Usage-2 Rate. A rate equal to that stated in the Statement of Rates for Transportation of Natural Gas, multiplied by that portion of the total quantity of Gas

RATE SCHEDULE ITS
Interruptible Transportation Service
(CONTINUED)

deliveries on any Day pursuant to the Agreement, which is greater than the lower of 110% of (i) the scheduled quantities of Gas under the Agreement for such Day or (ii) the MDQ in effect under the Agreement for such Day.

3.3 Other Applicable Charges or Surcharges. All applicable surcharges or charges, including, but not limited to, those contained in Sections 8 and 22 of the General Terms and Conditions and as stated in the Statement of Rates for Transportation of Natural Gas multiplied by each Dekatherm of Gas delivered.

3.4 Transporter's Use. Each Shipper will furnish Transporter fuel at the nominated Receipt Point(s). The amount of fuel furnished to Transporter will be based on the applicable percentage for Transporter's Use, as calculated pursuant to Section 22.2 of the General Terms and Conditions and as stated in the Statement of Rates for Transportation of Natural Gas.

3.5 Negotiated Rates. Shipper and Transporter may mutually agree, pursuant to the provisions of Section 30 of the General Terms and Conditions, to a negotiated rate, which rate shall be less than, equal to, or greater than Transporter's applicable maximum Recourse Rate, but shall not be less than the minimum rate. Such negotiated rate shall be set forth in an executed Agreement and/or in Transporter's Tariff and shall be agreed to in a written agreement between Transporter and Shipper.

3.6 Discounted Rates. Subject to any limitations agreed to by Shipper and Transporter, Transporter may from time to time and at any time selectively adjust any or all of the rates charged to any individual Shipper for any and all of the transportation routes for which a Maximum Rate and Minimum Rate are stated in the Statement of Rates for Transportation of Natural Gas of this Tariff or a superseding Tariff; provided, however, that such

RATE SCHEDULE ITS
Interruptible Transportation Service
(CONTINUED)

adjusted rate(s) shall not exceed the applicable Maximum Rate(s), nor shall they be less than the Minimum Rate(s), set forth on such sheets. Transporter shall have the right to charge the Maximum Rate at any time as a condition for new service, or for continuation of service under an existing Agreement. Transporter shall make all information filings and/or postings on LINK® required by the Commission's regulations with respect to any charges at less than the Maximum Rate.

4. COMMISSION AND OTHER REGULATORY FEES

Shippers will reimburse Transporter for any separately stated fees required by the Commission or any other federal or state regulatory body.

5. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions of this Tariff are specifically incorporated into this Rate Schedule.

RATE SCHEDULE PALS
Parking and Lending Service

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the parking and lending of Gas from Transporter, subject to the following limitations:

1.1 Transporter has determined that it is operationally able to render such service;

1.2 Shipper and Transporter have executed an Agreement under this Rate Schedule.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 This Rate Schedule shall apply to service which is rendered by Transporter for Shipper pursuant to an executed Agreement under this Rate Schedule.

2.2 Service under this Rate Schedule shall consist of either parking or lending of Gas during any Day, or part thereof. Service rendered by Transporter under this Rate Schedule shall be interruptible and shall consist of:

(a) Parking Service. Parking Service is an interruptible service which provides for (1) the receipt by Transporter of Gas quantities delivered by Shipper to receipt point(s) nominated by Shipper for receipt of parked quantities; (2) Transporter holding the parked quantities on Transporter's pipeline system; and (3) return of the parked quantities to Shipper, provided, however, that Transporter is not obligated to return parked quantities on the same Day and at the same point(s) at which the Gas is parked.

RATE SCHEDULE PALS
Parking and Lending Service
(CONTINUED)

(b) Lending Service. Lending Service is an interruptible service which provides for (1) Shipper receiving Gas quantities from Transporter at delivery point(s) nominated by Shipper for delivery of loaned quantities of Gas; and (2) the subsequent return of the loaned quantities of Gas to Transporter, provided, however, that Transporter is not obligated to accept return of loaned Gas on the same Day and at the same point(s) at which the Gas is loaned.

(c) If the Shipper receives parked quantities or returns loaned quantities at point(s) other than the point(s) at which the park or loan occurred, then Shipper and Transporter shall enter into a separate Transportation Agreement(s) to effectuate receipt or delivery of Gas from or to the new point(s).

2.3 Service rendered under this Rate Schedule shall be provided for a minimum of a one (1) Day term. The term shall be set forth on the Agreement executed between Shipper and Transporter.

2.4 Transportation of Gas quantities for or on behalf of Shipper to or from the designated point(s) under the Agreement shall not be performed under this Rate Schedule. Shipper shall make any necessary arrangements with Transporter and/or third parties to receive or deliver Gas quantities at the designated point(s) for Parking or Lending Service hereunder.

RATE SCHEDULE PALS
Parking and Lending Service
(CONTINUED)

3. RATES

Each Month, Shipper shall pay to Transporter the following rates:

3.1 Usage Rates.

(a) The applicable Usage Rate, as stated in the Statement of Rates for Transportation of Natural Gas, which shall be paid for each Dekatherm of Gas parked or loaned each Day at each point by Transporter for or on behalf of the account of Shipper multiplied by the highest balance of Gas quantities parked and/or loaned by Shipper on such Day;

(b) Other Applicable Charges or Surcharges. All applicable surcharges or charges including, but not limited to, those charges under Sections 8 and/or 22, and as stated in the Statement of Rates for Transportation of Natural Gas multiplied by each Dekatherm of Gas parked or loaned each Day at each point by Transporter for or on behalf of the account of Shipper.

3.2 Transporter's Use. Shipper shall not be required to furnish fuel for service under this Rate Schedule.

3.3. Negotiated Rates. Shipper and Transporter may mutually agree, pursuant to the provisions of Section 30 of the General Terms and Conditions, to a negotiated rate, which rate shall be less than, equal to, or greater than Transporter's Maximum Recourse Rate, but shall not be less than the minimum rate. Such negotiated rate shall be set forth in an executed Agreement and/or in Transporter's Tariff and shall be agreed to in a written agreement between Transporter and Shipper.

RATE SCHEDULE PALS
Parking and Lending Service
(CONTINUED)

3.4 Discounted Rates. Subject to any limitations agreed to by Shipper and Transporter, Transporter may from time to time and at any time selectively adjust any or all of the rates charged to any individual Shipper for service under this Rate Schedule for which a Maximum Rate and Minimum Rate are stated in the Statement of Rates for Transportation of Natural Gas of this Tariff or a superseding Tariff; provided, however, that such adjusted rate(s) shall not exceed the applicable Maximum Rate(s), nor shall they be less than the Minimum Rate(s), set forth on such sheets. Transporter shall have the right to charge the Maximum Rate at any time as a condition for new service, or for continuation of service under an existing Agreement. Transporter shall make all information filings and/or postings on LINK® required by the Commission's regulations with respect to any charges at less than the Maximum Rate.

4. OPERATIONAL REQUIREMENTS OF TRANSPORTER

4.1 Shipper may be required, upon notification from Transporter, to cease or reduce deliveries to, or receipts from, Transporter hereunder within a Day consistent with Transporter's operating requirements. Further, Shipper may be required to return loaned quantities or remove parked quantities upon notification by Transporter. Such notification shall, at a minimum, be provided by posting on LINK®, and may also be provided by other means of communication. Transporter's notification shall specify the time frame within which parked quantities shall be removed and/or loaned quantities shall be returned, consistent with Transporter's operating conditions, but in no event shall the specified time be sooner than the next Day after Transporter's notification, subject to the following conditions:

RATE SCHEDULE PALS
Parking and Lending Service
(CONTINUED)

(a) In the event that the specified time for removal or return of Gas quantities is the next Day, the time frame for required removal or return shall begin from the time that Shipper receives notice from Transporter. Notices provided after business hours for the next Day will be provided to Shipper via Electronic Communication. In the event that Shipper makes a timely and valid nomination in response to notification by Transporter to remove parked quantities and/or return loaned quantities, Shipper shall be deemed to have complied with Transporter's notification; and

(b) Unless otherwise agreed by Shipper and Transporter: (i) any parked quantity not nominated for removal within a time frame specified by Transporter's notice shall become the property of Transporter at no cost to Transporter free and clear of any adverse claims; (ii) any loaned quantity not returned within the time frame specified by Transporter's notice shall be sold to Shipper at Transporter's Cashout Price at the >25% Imbalance level for Imbalances Due Transporter, pursuant to Section 8.7(b) of the General Terms and Conditions.

Any penalty revenues received by Transporter as a result of the operation of Section 4.1(b) above will be credited pursuant to Section 23.1(a) of the General Terms and Conditions.

RATE SCHEDULE PALS
Parking and Lending Service
(CONTINUED)

4.2 In the event parked quantities remain in Transporter's pipeline system and/or loaned quantities have not been returned to Transporter's pipeline system at the expiration of any Agreement executed by Shipper and Transporter, Transporter and Shipper may mutually agree to an extended time frame and/or modified terms, including the rate, of such Agreement. In the event that Shipper and Transporter are unable to come to such Agreement, Transporter shall notify Shipper, and Shipper shall nominate for removal of the parked quantities and/or return of the loaned quantities within the time frame specified in Transporter's notice, which in no instance shall be less than one (1) Day. Any parked quantity not nominated for removal within the time frame specified by Transporter's notice shall become the property of Transporter at no cost to Transporter, free and clear of any adverse claims. Any loaned quantities not nominated to be returned within the time frame specified by Transporter's notice shall be sold to Shipper at Transporter's Cashout Price at the >25% Imbalance Level for Imbalances Due Transporter, pursuant to Section 8.7(b) of the General Terms and Conditions.

Any penalty revenues received by Transporter as a result of the operation of Section 4.2 above will be credited pursuant to Section 23.1(b) of the General Terms and Conditions.

5. COMMISSION AND OTHER REGULATORY FEES

Shippers will reimburse Transporter for any separately stated fees required by the Commission or any other federal or any state regulatory body.

6. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions of this Tariff are specifically incorporated into this Rate Schedule.

GENERAL TERMS AND CONDITIONS

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GENERAL TERMS AND CONDITIONS
(CONTINUED)

1. DEFINITIONS

In some instances, definitions are set forth in the Rate Schedules, General Terms and Conditions and the Forms of Service Agreements.

1.1 The term "Agreement" shall mean the agreement executed by the Shipper and Transporter and any applicable exhibits, attachments and/or amendments thereto.

1.2 The term "Backhaul" shall mean the receipt and delivery of Gas, which is accomplished by the Transporter's delivery of Gas at point(s) which are upstream from the point(s) at which Gas is received.

1.3 The term "Business Day" shall mean Monday through Friday, excluding Federal Banking Holidays for transactions in the United States.

1.4 The term "BTU" shall mean one (1) British thermal unit, the amount of heat required to raise the temperature of one (1) pound of water from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit, (BTU is measured and reported on a dry basis at 14.73 psia and 60 degrees Fahrenheit).

1.5 The term "Cashout" shall mean the monetary settlement of quantities of Gas owed to or by Transporter or third parties, as further described in Section 8 of these General Terms and Conditions.

1.6 The term "Cashout Party" shall mean any Shipper or other contractually liable entity who has an imbalance under any Agreement, which imbalance will be resolved in accordance with Section 8 of these General Terms and Conditions.

1.7 The term "Cashout Price" shall mean the price determined pursuant to Section 8 of these General Terms and Conditions.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.8 The term "Central Clock Time" or "CCT" shall mean Central Standard Time ("CST") except when Daylight Savings Time is in effect, when it shall mean one hour in advance of CST. All times referenced in Transporter's Tariff shall be in CCT.

1.9 The term "Commission" or "FERC" shall mean the Federal Energy Regulatory Commission or any successor regulatory authority.

1.10 The term "Confirmed Price" shall mean the Transportation rate inclusive of all applicable fees and surcharges agreed upon, in writing and/or via LINK®, by Transporter and Shipper or as otherwise required in this Tariff.

1.11 The term "Day" or "Gas Day" shall mean a period of 24 consecutive hours, beginning at 9:00 a.m. CCT, and ending on the following 9:00 a.m.

1.12 The term "Dekatherm" (or "Dth") shall mean the quantity of heat energy which is equivalent to one (1) million (1,000,000) BTU; thus the term Mdth shall mean one (1) thousand (1,000) Dth.

1.13 The term "Delivery Point" shall mean an interconnection point on Transporter's pipeline system that Shipper and Transporter shall agree upon, where Gas exits facilities owned by Transporter, and is metered.

1.14 The term "Delivery Point MDQ" shall mean the greatest number of Dekatherms that Transporter is obligated to deliver, on a Priority Class Onebasis to or on behalf of Shipper on any Day at the applicable Primary Delivery Point. The aggregate of the Delivery Point MDQs may not exceed the MDQ set forth in the Agreement; provided, however, a Shipper that has the Gulfstream Delivery Point as a Primary Delivery Point shall also have the FGT Delivery Point with a Delivery Point MDQ equal to such Shipper's Delivery Point MDQ at the Gulfstream Delivery Point.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.15 The term "Delivery Point Operator" shall mean the party that is responsible for operating the facilities that are immediately downstream of the applicable Delivery Point.

1.16 The term "Elapsed Prorata Capacity" shall mean that portion of the capacity that would have theoretically been available for use prior to the effective time of the intraday recall based upon a cumulative uniform hourly use of the capacity.

1.17 The term "Elapsed Prorated Scheduled Quantity" shall mean that portion of the scheduled quantity that would have theoretically flowed up to the effective time of the intraday nomination being confirmed, based on a uniform hourly flow rate for each nomination period affected.

1.18 The term "Electronic Communication" shall mean the transmission of information via Transporter's LINK® system, Electronic Delivery Mechanism prescribed by NAESB or other mutually agreed communication methodologies used to transmit and receive information.

1.19 The term "Electronic Delivery Mechanism" or "EDM" shall mean the Electronic Communication methodology used to transmit and receive data related to gas transactions. Transporter and Shipper shall designate an electronic "site" at which Shippers and Transporter may exchange data electronically. All data provided at such site shall be considered as being delivered to the appropriate party. Transporter's use and implementation of EDM shall conform to all appropriate NAESB standards.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.20 The term "Equivalent Quantities" shall mean a quantity of Gas containing an amount of Dekatherms equal to the amount of Dekatherms received by Transporter for the account of Shipper at the Receipt Point(s) reduced, where applicable, by the Dekatherms removed for Transporter's Use.

1.21 The term "FGT Delivery Point" shall mean the interconnections between Transporter's system and Florida Gas Transmission Company's system near Mobile, Alabama; and the interconnections between Transporter's system and Gulf South's system and Transco's system in the Mobile, Alabama area.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.22 The term "Force Majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of the public enemy, terrorist attacks, vandalism, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms (including but not limited to hurricanes or hurricane warnings), crevasses, floods, washouts, arrests and restraints of the government, either Federal or State, civil or military, civil disturbances. Force Majeure shall also mean shutdowns due to power outages and/or for purposes of necessary repairs, relocation, or construction of facilities; failure of electronic data capability; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by Transporter for the safe operation thereof), the necessity of making repairs or alterations to machinery or lines of pipe; failure of surface equipment or pipe lines; accidents, breakdowns, inability to obtain necessary materials, supplies or permits, or labor to perform or comply with any obligation or condition of service, rights of way; and any other causes, whether of the kind herein enumerated or otherwise which are not reasonably in Transporter's control. It is understood and agreed that the settlement of strikes or lockouts or controversies with landowners involving rights of way shall be entirely within Transporter's discretion and that the requirement in Section 16.1 of the General Terms and Conditions that any Force Majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts or controversies with landowners involving rights of way by acceding to the demands of the opposing party when such course is inadvisable in the discretion of Transporter.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.23 The term "Gas" shall mean natural gas, including cap gas, casinghead gas produced with crude oil, gas from gas wells, gas from condensate wells, synthetic natural gas, or any mixture of these gases meeting the quality standards under Section 3 of these General Terms and Conditions.

1.24 The term "Gas Delivered Hereunder" shall mean the quantities of Gas allocated to Shipper by Transporter, as determined in accordance with the provisions of Section 7 of these General Terms and Conditions.

1.25 The term "Gulfstream Delivery Point" shall mean the interconnection between Transporter's system and Gulfstream Natural Gas System, L.L.C.'s system near Coden, Alabama.

1.26 The term "High Common" shall mean the highest price listed under the heading "Common" in "Platts Gas Daily" "Daily Price Survey" for the applicable day.

1.27 The term "Imbalance Management Services" shall mean the options available to Shippers for resolution of imbalances including the application of the cashout mechanism set forth in Section 8 of the General Terms and Conditions. These options include service under PALS, Imbalance Netting and Trading and, as a final resolution, Cashout.

1.28 The term "Internet Website" shall mean Transporter's HTML site accessible via the Internet's World Wide Web located at http://www.link.duke-energy.com.

1.29 The term "LINK®" shall mean the LINK® Customer Interface System.

1.30 The term "Low Common" shall mean the lowest price listed under the heading "Common" in "Platts Gas Daily" "Daily Price Survey" for the applicable day.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.31 The term "Maximum Daily Quantity" ("MDQ") shall mean the greatest number of Dekatherms that Transporter is obligated to transport, on a firm basis, to or on behalf of Shipper on any day.

1.32 The term "Maximum PALS Quantity" ("MPQ") shall mean the greatest number of Dekatherms that shipper may have parked or loaned under its Rate Schedule PALS Agreement at any time.

1.33 The term "Mcf" shall mean one (1) thousand (1,000) cubic feet of Gas; the term MMcf shall mean one (1) million (1,000,000) cubic feet of Gas. (Mcf is measured on a dry basis at 14.73 psia. and 60 degrees Fahrenheit.)

1.34 The term "Month" shall mean the period beginning on the first Day of a calendar Month and ending at the same hour on the first Day of the next succeeding calendar Month.

1.35 The term "Monthly Imbalance" shall mean a Shipper's monthly quantity subject to resolution through the cashout mechanism described in Section 8 of the General Terms and Conditions, calculated as the difference between (i) allocated quantities received from a Cashout Party for the Month, as determined in accordance with Section 7 of the General Terms and Conditions, adjusted for Transporter's Use, and (ii) allocated quantities delivered to a Cashout Party for the Month, as determined in accordance with Section 7.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.36 The term "Negotiated Rate" shall mean a rate or rate formula for computing a rate for service under a single Agreement. For scheduling and curtailment purposes, a Shipper paying a Negotiated Rate in excess of the maximum Recourse Rate, will be considered to be paying the maximum Recourse Rate.

1.37 The term "Net Present Value" ("NPV") shall mean the discounted cash flow of expected revenues per Dekatherm of the applicable service for a term of up to twenty (20) years, using the interest rate set forth in Section 154.501 of the Commission's Regulations.

1.38 The term "Netting" shall be used to describe the process of resolving imbalances for a Shipper within an Operational Impact Area. There are two types of Netting:

a. Summing is the accumulation of all imbalances above any applicable tolerances for a Shipper or agent.

b. Offsetting is the combination of positive and negative imbalances above any applicable tolerances for a Shipper or agent.

1.39 The term "North American Energy Standards Board" or "NAESB" shall mean the accredited organization established to set standards for certain natural gas industry business practices and procedures.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

1.40 The term "Operational Impact Area" shall describe a Transportation Service Provider's (as defined by the NAESB Standards) designation of the largest possible area(s) on its system in which imbalances have a similar operational impact. For Transporter, the entire pipeline system shall comprise a single Operational Impact Area.

1.41 The term "Posted Point of Restriction" shall mean any point or segment on Transporter's pipeline system for which Transporter has posted on its web site a reduction of scheduled capacity notice, a notice that the point or segment is scheduled at its capacity, or a notice of expected restrictions due to weather, operating conditions or maintenance.

1.42 The term "Primary Delivery Point" shall mean the Delivery Point(s) as specified in the Agreement.

1.43 The term "Primary Receipt Point" shall mean the Receipt Point(s) as specified in Section 4.1 of Rate Schedule FTS.

1.44 The term "Receipt Point" shall mean an interconnection point on Transporter's pipeline system that Transporter and Shipper shall agree upon, where Gas enters facilities owned by Transporter, and is metered.

1.45 The term "Receipt Point MDQ" shall mean the greatest number of Dekatherms that Transporter is obligated to receive on a Priority Class Onebasis for or on behalf of Shipper on any Day at the applicable Primary Receipt Point(s). Receipt Point MDQs shall only be specified in Rate Schedule FTS Agreements that were executed by Transporter and Shipper on or before December 29, 2006.

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1.46 The term "Recourse Rate" shall mean the maximum rate for service set forth on the rate sheets in this Tariff for the applicable rate schedule.

1.47 The term "Receipt Point Operator" shall mean the party that is responsible for operating the facilities that are immediately upstream of the applicable Receipt Point.

1.48 The term "Reput" shall mean the reinstatement of a capacity release transaction that was recalled.

1.49 The term "Secondary Delivery Point" shall mean a Delivery Point that is not specified as a Primary Delivery Point.

1.50 The term "Service Day" shall mean the Day during which Shipper receives Transportation Service pursuant to a nomination in accordance with Section 4 of the General Terms and Conditions.

1.51 The term "Service Month" shall mean the Month during which Shipper receives services under this Tariff.

1.52 The term "Shipper" shall mean any person, corporation, limited liability company, partnership or any other legal entity who enters into an Agreement for service with Transporter.

1.53 The term "Tariff" shall mean Transporter's FERC Gas Tariff as effective from time to time.

1.54 The terms "Tender Gas" and "Tender of Gas" shall mean that the delivering party is able and willing, and offers, to deliver Gas to the receiving party at the appropriate Receipt Point or Delivery Point.

GENERAL TERMS AND CONDITIONS
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1.55 The term "Title Transfer" shall mean the change of title to Gas between parties at a location.

1.55A The term "Title Transfer Tracking" shall mean the process of accounting for the progression of title changes from party to party which process does not effect a physical movement of the Gas.

1.55B The term "Title Transfer Tracking Service Provider" or "TTTSP" shall mean a party conducting Title Transfer Tracking activities.

1.56 The terms "Transportation" and "Transportation Service" shall mean transportation of Gas by either forward haul, displacement or Backhaul or any combination thereof.

1.57 The term "Transportation Path" shall mean the transportation path from the Primary Receipt Point to the Primary Delivery Point.

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1.58 The term "Transporter" shall mean Southeast Supply Header, LLC.

1.59 The term "Transporter's Use" shall mean the quantity of Gas required by Transporter for compressor fuel, other company use and lost-and-unaccounted for Gas for service under each Agreement, and shall be equal to the Transporter's Use (%) under each such Agreement multiplied by Receipt Point quantities Tendered to Transporter.

1.60 The term "Transporter's Use (%)" shall mean the applicable percentage of Transporter's Use, which shall be an allocable amount of Transporter's Use, as calculated pursuant to Section 22.2, provided, however, that no Transporter's Use (%) shall be assessed on Backhaul transportation. The applicable percentage is shown in the Statement of Rates for Transportation of Natural Gas and shall be annually redetermined and filed to be made effective June 1 of each year in accordance with Section 22.2 of these General Terms and Conditions.

1.61 The "Usage-1 Rate" shall be stated in the Statement of Rates for Transportation of Natural Gas and shall be assessed as described in Section 3 of Rate Schedules FTS and ITS.

1.62 The "Usage-2 Rate" shall be stated in the Statement of Rates for Transportation of Natural Gas and shall be assessed as described in Section 3 of Rate Schedules FTS and ITS.

1.63 The term "Wire Transfer" shall mean payments made/effected by wire transfer (Fedwire, CHIPS, or Book Entry), or Automated Clearinghouse, or any other recognized electronic or automated payment mechanism that is agreed upon by Transporter in the future.

GENERAL TERMS AND CONDITIONS
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2. MEASUREMENT AND MEASUREMENT EQUIPMENT

2.1 (a) The volume of Gas delivered at the Receipt Point(s) and at the Delivery Point(s) shall be measured by one of the following devices installed by Transporter at its election, or as agreed to by Transporter and the operator of the interconnecting facilities:

(1) An orifice meter, designed and installed in accordance with the current edition of American National Standard ANSI/API 2530 (American Gas Association Report No. 3), entitled "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids" (hereinafter referred to as "AGA Report No. 3"); or

(2) A turbine meter, designed and installed in accordance with the current edition of American Gas Association Transmission Measurement Committee Report No. 7, entitled "Measurement of Gas by Turbine Meters", (hereinafter referred to as "AGA Report No. 7"); or

(3) An ultrasonic meter, designed and installed in accordance with the current edition of American Gas Association Transmission Measurement Committee Report No. 9, entitled "Measurement of Gas by Multipath Ultrasonic Meters" (hereinafter referred to as "AGA Report No. 9"); or

(4) A positive displacement meter, designed and installed in accordance with generally accepted industry practices.

(b) Meters shall be maintained and operated, and auxiliary measuring equipment shall be installed, maintained and operated, in accordance with generally accepted industry practices.

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(CONTINUED)

2.2 (a) The volume of Gas delivered at each Receipt Point and Delivery Point shall be calculated by means of an electronic flow computer located at each Receipt Point or each Delivery Point, in the following manner:

(1) The volume of Gas delivered through an orifice meter shall be computed in accordance with AGA Report No. 3, properly using all factors set forth therein.

(2) The volume of Gas delivered through a turbine meter shall be computed in accordance with AGA Report No. 7, properly using all factors set forth therein.

(3) The volume of Gas delivered through an ultrasonic meter shall be computed in accordance with AGA Report No. 9, properly using all factors set forth therein.

(4) The volume of Gas delivered through a positive displacement meter shall be computed by properly applying, to the volume delivered at flowing Gas pressures and temperatures, correction factors for (i) absolute static pressure, (ii) flowing Gas temperature, and (iii) compressibility ratio.

(b) The volume of Gas delivered shall be computed using the standards and factors determined as follows:

(1) The unit of volume for the purpose of measurement shall be one thousand cubic feet of Gas at a temperature of sixty (60) degrees Fahrenheit and a pressure of 14.73 pounds per square inch absolute. For the purpose of pricing hereunder, the Dekatherm equivalent of such unit of volume shall be determined by multiplying each such unit of volume by the total heating value per cubic foot of the Gas delivered hereunder (adjusted to a common temperature and pressure base) and by dividing the result by one thousand (1000).

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(CONTINUED)

(2) The average absolute atmospheric (barometric) pressure at each Receipt Point and each Delivery Point shall be assumed to be 14.7, irrespective of the actual location or elevation above sea level of the Receipt Point or Delivery Point or of variations in actual atmospheric pressure from time to time.

(3) The static pressure and temperature of the Gas at flowing conditions through a meter and, where applicable, the differential pressure across the orifice plate of an orifice meter shall be determined by means of instruments of standard manufacture accepted in the industry for these purposes.

(4) The supercompressiblity factor used in computing the volume of Gas delivered through an orifice meter shall be determined using the procedures presented in American Gas Association Transmission Measurement Committee Report No. 8, entitled "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases."

(5) The specific gravity of the Gas used in computing the volume of Gas delivered through a meter shall be determined at each Receipt Point and at strategic locations determined by Transporter to be representative for each Delivery Point by standard methods accepted in the industry for this purpose.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

(6) The compressibility ratio factor "s" used in computing the volume of Gas delivered through a turbine meter, an ultrasonic meter, or a positive displacement meter shall be determined by the equation s = (Fpv)2, in which "Fpv" is the supercompressiblity factor determined as described in subparagraph (4) of this subsection (b).

2.3 All flow measuring, testing and related equipment shall be of standard manufacture and type approved by Transporter. If applicable, Transporter or Shipper may install check measuring equipment and telemetering equipment, provided that such equipment shall be so installed as not to interfere with the operations of the operator. Transporter, or Shipper, in the presence of the other party, shall have access to measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the operator of the facilities. Transporter or Shipper shall have the right to be present at the time of the installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting done by the operator of the measuring equipment. The records from such measuring equipment shall remain the property of the operator, but upon request the other party may request records including charts, together with calculations therefrom for inspection, subject to return within thirty (30) days after receipt thereof. Reasonable care shall be exercised in the installation, maintenance and operation of the measuring equipment so as to avoid any inaccuracy in the determination of the volume of Gas received and delivered.

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(CONTINUED)

The accuracy of all measuring equipment shall be verified by operator at least once each year and if requested, in the presence of representatives of the other party, but neither Transporter nor Shipper shall be required to verify the accuracy of such equipment more frequently than once in any thirty (30) Day period. If the operator agrees to verification and test of measuring equipment and fails to perform such verification and testing, then the other party shall have the right to cease or temporarily discontinue service relative to such measuring equipment. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other party and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses involved in the testing of meters shall be borne by the party incurring such expenses, provided, however, that Shipper shall not be responsible for such Transportation and related expenses if the special testing reveals that the meter(s) is (are) not operating within the required tolerance level of one percent (1%).

The operator, for purposes of this section, shall be the owner of the equipment referenced herein, or the agent of such owner, or such other person as the parties may agree in writing.

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If, upon any test, any measuring equipment is found to be in error, such errors shall be taken into account in a practical manner in computing the deliveries. If the resultant aggregate error in the computed receipts or deliveries is not more than one percent (1%), then previous receipts or deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record correctly. If, however, the resultant aggregate error in computing receipts or deliveries exceeds one percent (1%), the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon, but in case the period is not known definitely or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test.

2.4 In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, previous recordings of receipts or deliveries through such equipment shall be determined as follows; provided, however, that the correction period shall be within six (6) Months of the production Month, with a three (3) Month rebuttal period and provided, further, that such standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard:

(a) by using the registration of any check meter or meters if installed and accurately registering, or in the absence of (a);

(b) by correcting the error if the percentage of error is ascertainable by calibration, special test or mathematical calculation, or in the absence of both (a) and (b) then;

GENERAL TERMS AND CONDITIONS
(CONTINUED)

(c) by estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the meter was registering accurately.

2.5 If at any time during the term hereof, a new method or technique is developed with respect to Gas measurement or the determination of the factors used in such Gas measurement, such new method or technique may be substituted upon mutual agreement thereto by both parties.

2.6 The parties agree to preserve for a period of at least three (3) years or such longer period as may be required by public authority, all test data, if any, and other similar records.

2.7 Shipper or Transporter may install, maintain, and operate odorizing (at a Delivery Point only), regulating, telemetering, heating and fogging equipment at its own expense as it shall desire at each Receipt Point or Delivery Point, and the operator of such equipment at its own expense shall provide the other party a suitable site therefore and allow the other party free access to and use of the site; provided that such equipment shall be so installed, maintained and operated as not to interfere with the operation or maintenance of the operating party's measuring equipment at each Receipt Point or Delivery Point. All such equipment as Shipper or Transporter shall desire to install shall be constructed, installed and operated to conform to the other party's requirements.

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(CONTINUED)

3. QUALITY OF GAS

3.1 Except as expressly set forth herein to the contrary, the gas received or delivered by Transporter shall be a combustible gas consisting of methane and such other hydrocarbon constituents or a mixture of two or more of them which, in any case, meets the following qualify specifications:

(A) The gas shall have a total heating value not less than one thousand (1,000) Btu per cubic foot of gas nor greater than one thousand seventy-five (1,075) Btu per cubic foot of gas;

(B) Transporter may not refuse to accept delivery of gas with a hydrocarbon dew point equal to or less than 15 degrees Fahrenheit, provided that such gas satisfies all other applicable provisions of Transporter's Tariff.

(1) To the extent operationally practicable through aggregation or other reasonable means, Transporter may accept gas with a higher hydrocarbon dew point than that established in 3.1(B), but not exceeding (.04) gallons per Mcf (GPM)of C6+.

(C) The gas shall be commercially free, under continuous gas flow conditions, from objectionable odors, solid matter, dust, gums, gum-forming constituents, water or any other solid or liquid matter which might cause damage to or interference with proper operations of the pipeline, compressor stations, meters, regulators or other appliances through which the gas flows;

(D) The gas shall not have uncombined oxygen content in excess of two-tenths (0.2) of one percent (1%) by volume;

(E) The gas shall not contain more than three (3.0%) by volume, of a combined total of carbon dioxide and nitrogen;

(F) The gas shall not contain more than one-quarter (0.25) grain of hydrogen sulfide per one-hundred (100) cubic feet;

(G) The gas shall not contain more than ten (10) grains of total sulphur, excluding any mercaptan sulphur, per one-hundred (100) cubic feet;

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(CONTINUED)

(H) The flowing gas shall not have a temperature of more than one-hundred twenty degrees (120) Fahrenheit or less than forty (40) degrees Fahrenheit.

(I) The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received and delivered.

(J) The gas shall not contain in excess of seven (7) pounds of water vapor per million cubic feet;

(K) The gas shall not contain, either in the gas or in any liquids with the gas, any microbiological organism, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems. Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (APB). Tests for bacteria or bacterial agents shall be conducted on samples taken from the meter run or the appurtenant piping using American Petroleum Institute (API) test method API-RP38 or any other test method acceptable to Transporter and Shipper which is currently available or may become available at any time.

3.2 The test equipment and methodology utilized by Transporter to determine whether gas meets the qualify specifications set forth in Section 3.1 shall be posted on its LINK® System.

3.3 At Transporter's request, Shipper shall use all reasonable efforts to obtain and provide to Transporter all records regarding gas quality kept by upstream pipelines transporting the gas received by Transporter for Shipper's account. Shipper shall use all reasonable efforts to ensure and verify for Transporter that such upstream pipelines are using appropriate equipment to monitor compliance with the gas quality specifications applicable on Transporter's system as stated in this Section 3.

3.4 If the gas tendered for Shipper's account to Transporter shall fail at any time to conform to any of the specifications set forth in this Section 3 or in Transporter's reasonable judgment, may cause harm to its facilities or diminish the quality of gas in the system, then Transporter shall have the right, after either written, oral or telephonic notice to Shipper, to refuse to accept all or any portion of such quality deficient gas. In the event Transporter refuses to accept

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gas tendered by Shipper because such gas does not conform to the specifications set forth herein, Shipper shall not be relieved of its obligation to pay any Reservation Charge provided for in Shipper's service agreement. If the gas tendered by Transporter for Shipper's account shall fail at any time to conform to any of the specifications set forth in this Section 3 then Shipper shall notify Transporter of such deficiency and may, at its option, refuse to accept delivery pending correction by Transporter.

3.5 Transporter may waive the requirements set forth in Section 3.1 in order to allow Shipper to tender or cause to be tendered, gas which does not when injected into Transporter's pipeline meet the quality specifications set forth in Section 3.1; provided that Transporter's acceptance of such gas shall not adversely impact Transporter's system facilities or operations, and further provided that once such gas has been blended, to the extent blending occurs, the commingled gas stream at any delivery point on Transporter's system shall be compliant with the quality specifications set forth in Section 3.1. Transporter shall implement this Section 3.5 on a non-discriminatory basis and may cancel any waiver at any time if necessary to assure that the commingled gas stream is compliant with the quality specifications set forth in Section 3.1 at any delivery point on Transporter's system.

3.6 Odorization. Transporter shall have no obligation to odorize the gas tendered by Shipper other than to conform to the regulations of appropriate governmental authorities having jurisdiction. However, if Transporter odorizes the gas, such odorization shall be by use of a malodorant agent of such character as to indicate by a distinctive odor the presence of gas. Whenever odorized gas is delivered, the quality and specifications, as set forth in this Section 3, of such gas shall be determined prior to the addition of malodorant or with proper allowance for changes or additions due to such malodorant. Such odorization of the gas by Transporter shall be for the purpose of detection of the gas only during the time when the gas is in the possession of Transporter, prior to delivery to the Shipper.

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4. NOMINATIONS

4.1 Transporter shall accept nominations twenty-four (24) hours a day via the LINK® System or EDM. All nominations must contain the mandatory data elements included in the NAESB standards and any additional business-conditional or mutually agreeable data elements applicable to Transporter’s services. All nominations shall include Shipper defined begin dates and end dates. All nominations excluding intra-day nominations should have roll-over options. Specifically, Shippers have the ability to nominate for several Days, Months, or years, provided the nomination begin and end dates are within the term of the Shipper's Agreement. Nominations under Rate Schedule FTS must be for a minimum period of one (1) Day, and all quantities must be stated in Dths. Nominations under Rates Schedule ITS or PALS must specify the daily scheduled quantity, and all quantities must be stated in Dekatherms. At the end of each Day, Transporter will provide the final scheduled quantities for the just completed Day. With respect to the implementation of this process via NAESB Standard No. 1.4.x scheduled quantity related standards, Transporter should send an end of Day Scheduled Quantity document. Receivers of the end of Day Scheduled Quantity document can waive the sender's sending of the end of Day Scheduled Quantity document.

(a) All nominations must be communicated via the LINK® System or EDM unless otherwise mutually agreed and must be submitted in accordance with the standard nomination timelines set forth below. A revised nomination supersedes the previous nomination in effect, but only for the Days specified in such revised nomination, after which the previous nomination once again takes effect until its end date or time or until superseded by another new or revised nomination, whichever is earlier.

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The standard nomination timelines are as follows:

(1) The Timely Nomination Cycle:
(All times are CCT on the day prior to the Service Day)

11:30 a.m. Latest time that nominations may leave control of the nominating party;

11:45 a.m. Receipt of nominations by Transporter (including from Title Transfer Tracking Service Providers (TTTSPs));

12:00 p.m. Transporter sends quick response;

3:30 p.m. Receipt of completed confirmations by Transporter from upstream and downstream connected parties;

4:30 p.m. Receipt of scheduled quantities by Shipper and point operator.

Scheduled quantities resulting from the Timely Nomination Cycle shall be effective at 9:00 a.m. CCT on the next Service Day.

(2) The Evening Nomination Cycle (All times are CCT on the Day prior to the Service Day.)

6:00 p.m. Latest time that nominations may leave control of the nominating party;

6:15 p.m. Receipt of nominations by Transporter (including from TTTSPs);

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6:30 p.m. Transporter sends quick response;

9:00 p.m. Receipt of completed confirmations by Transporter from upstream and downstream connected parties;

10:00 p.m. Transporter to provide scheduled quantities to affected Shippers and point operators, and to provide scheduled quantities to bumped parties (notice to bumped parties).

Scheduled quantities resulting from an Evening Nomination that does not cause another Shipper on Transporter to receive notice that it is being bumped should be effective at 9:00 a.m. CCT on the next Service Day; and when an Evening Nomination causes another Shipper on Transporter to receive notice that it is being bumped, the scheduled quantities should be effective at 9:00 a.m. CCT on the next Service Day.

(3) The Intra-day 1 Nomination Cycle: (All times are CCT on the Service Day.)

10:00 a.m. Latest time that nominations may leave control of the nominating party;

10:15 a.m. Receipt of nominations by Transporter (including from TTTSPs);

10:30 a.m. Transporter sends quick response;

1:00 p.m. Receipt of completed confirmations by Transporter from upstream and downstream connected parties;

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2:00 p.m. Transporter to provide scheduled quantities to affected Shippers and point operators, and to provide scheduled quantities to bumped parties (notice to bumped parties).

Scheduled quantities resulting from the Intra-day 1 Nomination Cycle shall be effective at 5:00 p.m. CCT on the same Service Day.

(4) The Intra-Day 2 Nomination Cycle: (All times are CCT on the Service Day.)

5:00 p.m. Latest time that nominations may leave control of the nominating party;

5:15 p.m. Receipt of nominations by Transporter (including from TTTSPs);

5:30 p.m. Transporter sends quick response;

8:00 p.m. Receipt of completed confirmations by Transporter from upstream and downstream connected parties;

9:00 p.m. Transporter to provide scheduled quantities to affected Shippers and point operators.

Scheduled quantities resulting from the Intra-Day 2 Nomination Cycle shall be effective at 9:00 p.m. CCT on the same Service Day. Bumping is not allowed during the Intra-Day 2 Nomination Cycle.

For purposes of Sections 4.1(a)(2), 4.1(a)(3), and 4.1(a)(4) above, "provide" shall mean, for transmittals pursuant to standards 1.4.x, receipt at the designated site, and for purposes of other forms of transmittal, it shall mean send or post.

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(b) Shipper shall include in its nominations the desired order of priority of receipts and deliveries under each Agreement which Transporter will use when taking action to change receipts and/or deliveries according to Section 5.2. The order of priority shall indicate that a priority of one (1) shall be the last to be affected by changes. Nominations with the same priority will be adjusted pro rata.

(c) If Shipper completes and resubmits an otherwise incomplete nomination, then Transporter will process the nomination in the first nomination cycle that occurs where the Shipper's complete nomination meets the deadline for nominations.

(d) Variations by Shipper of actual receipts and deliveries from the nominated receipts and deliveries shall be kept to a minimum. Receipts and deliveries shall be made at uniform hourly rates unless provisions to deliver the Gas at a non-uniform rate are confirmed by Transporter's Gas Control Department prior to Gas flowing. Under no circumstances shall Transporter be obligated to deliver to any Shipper, on any Day, a quantity of Gas under any Agreement greater than Transporter received at the Receipt Point(s) on behalf of such Shipper under such Agreement.

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(e) Any shipper may designate an agent, which may be Transporter, to nominate and schedule transportation service on Shipper's behalf. Shipper shall notify Transporter, in writing or via the LINK® System, of the designated agent. Transporter is authorized to rely on nominations and scheduling information provided by Shipper's agent. By designating an agent, Shipper agrees to indemnify and save Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising in any way from Shipper's agent's actions on behalf of Shipper, Shipper's agent's failure to act on behalf of Shipper, or Transporter's reliance upon the information provided to Transporter by Shipper's agent; provided, however that such indemnification will not excuse Transporter from liability for actions taken when Transporter is acting as agent.

4.2 Implementation of Intra-day Nominations.

(a) Subject to the deadlines in Section 4.1(a)(2),(3) or (4), above, intra-day nominations may be nominated twenty-four (24) hours a Day and will be processed in the same manner as other nominations. However, the nomination deadline and effective time of intra-day nominations specified in Section 4.1 (a) will not apply to OFO related intra-day nominations.

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(b) Subject to upstream and downstream operators' confirmations and Transporter's operating conditions, an intra-day nomination submitted pursuant to one of the deadlines set forth in Section 4.1(a) above can be used to request increases or decreases in total flow, changes to Receipt Points, or changes to Delivery Points of scheduled Gas.

(c) With respect to intraday nominations for reductions in previously scheduled quantities, Transporter will accept, subject to the limitations set forth in Section 4.1(a), any explicitly confirmed quantity, down to and including zero, for such intraday nomination; provided, however, if such intraday nomination requires confirmation from an upstream and/or downstream interconnected pipeline then any intraday nomination to reduce previously scheduled quantities will be subject to, and limited to, the reduced quantity confirmed by such upstream and/or downstream interconnected pipeline.

(d) Transporter shall allow Shipper to alter the order of priority of receipts and deliveries upon which Transporter shall rely in taking actions to adjust receipts and/or deliveries under Section 4.1 above, provided that such changes are submitted via the LINK® System or EDM in accordance with the nomination deadlines set forth in 4.1(a), above.

(e) Notice. For purposes of providing notice of any nomination changes (including where an interruptible Shipper's nomination is bumped by a firm Shipper's intra-day nomination) to a Shipper and/or Shipper's agent, Transporter shall use Electronic Communication.

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5. PRIORITY OF SERVICE

5.1 Transporter shall have the right to curtail or discontinue services, in whole or in part, on all or a portion of its system at any time for reasons of Force Majeure or when capacity or operating conditions so require, or it is necessary to make modifications, repairs or operating changes to its system. Transporter shall provide Shipper notice of such curtailment as is reasonable under the circumstances. Notwithstanding anything to the contrary contained in this Section 5.1, Transporter will schedule routine repairs and maintenance in a manner that to the greatest extent possible will not disrupt the flow of quantities scheduled and confirmed in accordance with Section 4 of the General Terms and Conditions.

5.2 For each nomination cycle, Transporter shall allocate capacity on the basis of nominations made by Shippers, utilizing the priorities of service, from highest to lowest, as set forth below:

(a) Priority Class One. Rate Schedule FTS Primary Receipt Point(s) and Primary Delivery Point(s) within MDQ.

(b) Priority Class Two. Rate Schedule FTS. Secondary Delivery Point(s) within MDQ within the Transportation Path.

(c) Priority Class Three. Rate Schedule FTS. Secondary Delivery Point(s) within MDQ and outside the Transportation Path.

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(d) Priority Class Four. Rate Schedule ITS, Rate Schedule PALS.

(e) Priority Class Five. Make-up Gas scheduled at Transporter's discretion.

For purposes of determining whether points are located within the Transportation Path, Transporter shall consider a movement of gas from a Receipt Point to a Delivery Point which is counter to the gas flow contemplated by the Primary Receipt Point(s) and Primary Delivery Point(s) as outside the Shipper's Transportation Path. In addition, for any movement of gas that traverses a segment(s) in which the total nominated quantity for that contract exceeds the Transportation Path MDQ, the quantity in excess of the contractual entitlement shall be deemed to be outside of the Shipper's Transportation Path.

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6. SCHEDULING AND CURTAILMENT

6.1 Scheduling Capacity during a Start of Day Nomination Cycle.

(a) Transporter shall allocate its pipeline capacity as well as each Receipt Point and each Delivery Point capacity on the basis of the priority classes listed in Section 5 above as follows:

(i) prorata for Priority Class One nominations; then
(ii) prorata for Priority Class Two; then
(iii) prorata for Priority Class Three; then
(iv) on the basis of Confirmed Price for Priority Class Four; then
(v) make-up gas for FTS Agreements, then make-up gas for ITS Agreements.

(b) Ties within any Priority Class shall be allocated pro rata based on nominations.

6.2 Scheduling Available Capacity during an Intra-day Nomination Cycle. Transporter shall schedule available capacity during each of the Intra-day Nomination Cycles in accordance with Section 6.1 above. Bumping of service is not allowed during the Intra-Day 2 Nomination Cycle which is effective at 9:00 p.m. CCT on the same service Day and all cycles thereafter for the remainder of the Day.

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6.3 Curtailment of Scheduled Volumes during a Day. If, at any time, Transporter determines that the capacity of its system, or portion(s) thereof, is insufficient to serve all scheduled service, or to accept the quantities of Gas tendered, capacity which requires curtailment shall be curtailed so as to provide the service which is feasible in the order prescribed for Scheduling in Section 6.1 above; provided, however, once scheduled, Priority Class Two and Priority Class Three will have the same curtailment priority as Priority Class One; and provided, further, if a capacity constraint occurs on the upstream or downstream system which results in a curtailment, the upstream or downstream operator shall determine the change in scheduled nominations of its Shippers. Such change in scheduled nominations shall be confirmed via the LINK® System or EDM. To enable prompt action in an emergency situation where capacity is insufficient, Transporter shall have the authority to take all necessary and appropriate actions, as then may appear necessary, to preserve the operational integrity of its system. Transporter shall notify Shippers of the existence of any such emergency situation by use of Electronic Communication, as soon as it is reasonably practicable.

6.4 Segmentation of Capacity by Nomination. Any Shipper receiving Transportation Service under Rate Schedule FTS shall have the right to segment its firm capacity by utilizing multiple Receipt Points and Delivery Points. The right to segment is subject to the requirement that a Shipper's firm capacity utilization pursuant to its Rate Schedule FTS Agreement and, if such Agreement is the result of capacity release, the firm capacity utilization of all other Shippers of capacity rights derived from the initial Rate Schedule FTS Agreement, does not exceed, in the aggregate (based on all relevant Shipper firm capacity utilization), the contract entitlements of the initial Rate Schedule FTS Agreement in any segment or at any point (including, without limitation, the relevant MDQ) where the nominated segments overlap. For the purpose of determining whether there is an overlap of MDQ, a forward haul and a Backhaul nominated to the same

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Delivery Point at the same time shall not be deemed to be an overlap at that point. For the purpose of determining whether there is an overlap of MDQ on a segment, a forward haul and a Backhaul nominated on the same segment at the same time shall be deemed to be an overlap on the segment. As a general matter, Shipper will have the right to segment its capacity so long as it is utilizing its Primary Receipt Point(s) and Primary Delivery Point(s), as well as all Secondary Delivery Points, as long as such use does not impair Transporter's ability to render firm Transportation Service, does not adversely affect Shippers' firm Transportation Service rights, and/or does not adversely affect the safe and reliable operation of Transporter's pipeline system.

6.5 Segmentation of Capacity by Capacity Release. Releasing Shippers can also segment capacity through capacity release in accordance with Section 25 of the General Terms and Conditions of Transporter's Tariff, subject to the requirement that the release (or multiple releases) does not increase the total contract entitlements in any segment or at any point (including, without limitation, the relevant MDQ) above the contract entitlement of the initial Rate Schedule FTS Agreement. For the purpose of determining whether there is an overlap of MDQ, a forward haul and a Backhaul nominated to the same Delivery Point at the same time shall not be deemed to be an overlap at that point. As a general matter, Shipper will have the right to segment its capacity so long as it is utilizing its Primary Receipt Point(s) and Primary Delivery Point(s), as well as all Secondary Delivery Points, as long as such use does not impair Transporter's ability to render firm Transportation Service, does not adversely affect Shippers' firm Transportation Service rights, and/or does not adversely affect the safe and reliable operation of Transporter's pipeline system and/or does not result in quantities being nominated in any manner that is inconsistent with Section 25.1(a) of these General Terms and Conditions.

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7. DETERMINATION OF DAILY ALLOCATED RECEIPTS AND DELIVERIES

7.1 Allocation of Receipts/Deliveries. Unless Transporter and Operator mutually agree to allocate deliveries each Day using ranked, pro rata, percentage, swing or operator provided value methodologies, such deliveries will be allocated through the meter pro rata, to the extent applicable, based on confirmed nominations.

Operator shall notify Transporter via LINK® after or during confirmation and before start of the Day, that it desires to establish allocation priorities at Receipt and/or Delivery Points using any of the following methodologies: ranked, prorata, percentage, swing or Operator provided value provided, however, Transporter will not be required to agree to any of such allocation methodologies if they are operationally or administratively infeasible.

Transporter shall advise such Operator of the confirmed nominations at such Receipt/Delivery Point.

The Operator shall establish separate allocation priorities for over and under production at the level of detail that the confirmed nominations are provided, and advise Transporter of such priorities via LINK® before the beginning of the Day. Any confirmed nominations that do not have established allocation priorities shall be prorated based upon confirmed nominations and shall be allocated after all confirmed nominations that have established allocation priorities.

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In the case of under production, such allocation priorities shall be used by Transporter to allocate Gas, such that Transporter shall allocate Gas to each Shipper, in order of priority designated by the Operator, up to the full nomination of that Shipper, until the entire gross measured volume at such Receipt/Delivery Point is allocated.

In the case of over production, such allocation priorities shall be used by Transporter to allocate Gas, such that Transporter shall allocate Gas to each Shipper, in order of priority designated by the Operator, equal to the full nomination of that Shipper, with any over produced quantities being allocated to the Shipper(s) with the lowest priority, until the entire gross measured volume at such Receipt/Delivery Point is allocated.

Simultaneous Receipts and Deliveries. To the extent that both receipts and deliveries have been nominated at the same meter for any day:

If the actual flow through the meter represents a delivery by Transporter, then the nominated receipts shall be allocated as nominated and the sum of such receipts shall be added to the metered quantity before any allocation is made in accordance with Section 7.1; or

If the actual flow through the meter represents a receipt by Transporter, then the nominated deliveries shall be allocated as nominated and the sum of such deliveries shall be added to the metered quantity before any allocation is made in accordance with Section 7.1.

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7.2 Prior Period Adjustments.

In accordance with the provisions of Sections 2 and 11 of these General Terms and Conditions, Transporter shall use the best information available to close its allocation of quantities for a Service Month five (5) Business Days after such Service Month. To the extent that adjustments are made after the date of such close, such adjustments ("Prior Period Adjustments" or "PPA") shall be treated under this Section 7.2. If the PPA is due to the correction of measurement data or allocations, such adjustments shall be processed within six (6) Months of the applicable Service Month. If the affected party disputes the as-adjusted quantity, it is entitled to rebut the basis for the PPA, but only if it does so within three (3) Months of the processing of the PPA. Notwithstanding the above-specified deadlines for processing/rebutting PPAs, such deadlines shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not be diminished by this standard.

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7.3 Trespass Gas. Gas that is received by Transporter during a Service Month at a Receipt Point for which there is no valid nomination shall be considered Trespass Gas. If Transporter receives Trespass Gas during a Service Month, it shall post such fact on LINK®, including the location and quantity of such Trespass Gas, for a period of thirty (30) Days after the end of the Service Month. The owner of such Trespass Gas may claim such Gas by informing Transporter in writing of such fact and by having the ownership verified by the Operator of the facilities upstream of the Receipt Point. Upon receiving a valid claim of ownership, Transporter shall first give the claimant the opportunity to move the Gas off of Transporter's system upon payment of the applicable Transportation and PALS charges. Alternatively, the claimant may request payment of an amount (as full consideration, inclusive of taxes and any other amounts) equal to the product of the quantity of Trespass Gas times the Low Common price (as determined pursuant to Section 8.7 of the General Terms and Conditions) for the Service Month in which the Trespass Gas was received. If there is no valid claim for such Trespass Gas within such thirty (30) day posting period, Transporter shall be allowed to retain such Trespass Gas.

7.4 Conversion of Gas. Any party that takes Gas without Transporter's authorization shall be liable for paying the High Common price (as determined pursuant to Section 8.7 of the General Terms and Conditions) for the Month in which the Gas was taken, in addition to any other costs, losses, and damages attributable to such taking, in addition to any legal remedies otherwise available.

Any penalty revenues received by Transporter as a result of the operation of Sections 7.3 and 7.4 above will be credited pursuant to Sections 23.2 and 23.3 of the General Terms and Conditions.

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8. IMBALANCE RESOLUTION PROCEDURES

8.1 For the purposes of this Section 8, "Receipt" or "Receipts" shall mean quantities of Gas allocated pursuant to Section 7 of these General Terms and Conditions, net of Transporter's Use, and "Delivery" or "Deliveries" shall mean quantities of Gas allocated pursuant to Section 7. After the end of each Service Month, Transporter shall render to Cashout Party a statement detailing any imbalance between Monthly Receipts and Monthly Deliveries under all of Cashout Party's Transportation Agreements ("Imbalance Statement"), subject to Transporter's Billing and Payment provisions contained in Sections 9 and 10 of these General Terms and Conditions.

8.2 Cumulative Daily Transportation Imbalances shall be subject to the following imbalance resolution procedures.

(a) Definition of Transportation Imbalance: "Transportation Imbalance" shall mean the difference between a Shipper's allocated Receipts and allocated Deliveries under any firm or interruptible Agreement. All imbalances will be calculated on a daily basis and designated to be at the applicable Receipt Point.

(b) Definition of an Imbalance Due Cashout Party: "Due Cashout Party" shall mean that Deliveries under an Agreement at the Delivery Point are less than Receipts at the Receipt Point, adjusted for Transporter's Use; such difference in quantity is "Due To" a Cashout Party (or its Agent).

(c) Definition of an Imbalance Due Transporter: "Due Transporter" shall mean that Deliveries under an Agreement at the Delivery Point exceed Receipts at the Receipt Point, adjusted for Transporter's Use; such difference in quantity is "Due From" a Cashout Party (or its Agent).

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8.3 Netting: For each Month, all cumulative Transportation Imbalances within an Operational Impact Area will be netted among each of Cashout Party's firm and interruptible Agreements.

8.4 Trading: Posting and trading of the previous Month's netted Transportation Imbalances will be allowed within each Operational Impact Area between imbalance agents (or the Cashout Party, if no imbalance agent exists) from the first calendar Day of the current Month until the end of the 17th Business Day of the current Month. Imbalances to be posted for trading should be authorized by the Cashout Party. Authorizations to post imbalances that are received by Transporter by 11:45 A.M. should be effective by 8:00 A.M. the next Business Day (Central Clock Time). Imbalances previously authorized for posting should be posted on or before the ninth Business Day of the month. Transporter should provide the ability to view and, upon request, download posted imbalances. Transporter should not be required to post zero imbalances. When trading imbalances, a quantity should be specified. Trading will be allowed

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only when (i) imbalances are within the same Operational Impact Area and (ii) the resulting trade will reduce the imbalances for each Cashout Party or its imbalance agent. Transporter shall allow Cashout Parties to trade imbalances with other Cashout Parties within the same Operational Impact Area if the two Cashout Parties' imbalances are offsetting balances such that the net imbalance for each Cashout Party after the completion of the trade would be reduced to a quantity closer to zero. A Cashout Party may trade any imbalance with another Cashout Party, provided that the trade shall not result in a Transportation Path which crosses a Posted Point of Restriction; provided further that to the extent the imbalances were incurred during the remainder of the month when no posted point of restriction was in effect, those imbalances are available for trading. Transporter should enable the imbalance trading process by receiving the request for imbalance trade, receiving the imbalance trade confirmation, sending the imbalance trade notification, and reflecting the trade prior to or on the next monthly Shipper imbalance or cashout statement. After receipt of an imbalance trade confirmation, Transporter should send the imbalance trade notification to the initiating trader and the confirming trader no later than noon (Central Clock Time) the next Business Day. Imbalance trades can only be withdrawn by the initiating trader and only prior to the confirming trader's confirmation of the trade. Imbalance trades are considered final when confirmed by the confirming trader and effectuated by Transporter.

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8.5 Final Resolution of Transportation Imbalances: If Cashout Party has a Transportation Imbalance remaining after the close of the trading period, such Transportation Imbalance will be cashed out in accordance with the cashout provisions set forth in Section 8 herein.

8.6 All balancing shall be based on the applicable Delivery Point within an Operational Impact Area. Cashout Party or its Agent(s) may nominate transactions (in accordance with Section 4 of the General Terms and Conditions) during the Month to correct Transportation Imbalances within an Operational Impact Area. Transporter's ability to receive or deliver imbalance quantities shall be dependent upon Transporter's physical operations, and Transporter is under no obligation to allow Receipt or Delivery of such quantities for resolution of Transportation Imbalances if it determines, such activity would jeopardize pipeline operations.

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8.7 Cashout Provision. At the time Transporter tenders an invoice(s) to Cashout Party for Transportation Service during the previous Month, Transporter shall invoice Cashout Party, or credit Cashout Party's invoice, as appropriate, to resolve in cash any net monthly Imbalance remaining between actual Receipts, adjusted for Transporter's Use, and actual Deliveries after the period during which the relevant Transportation Imbalance quantities have been subjected to the imbalance resolution mechanisms set forth in this Section 8. Transporter will send with each invoice a statement detailing the unresolved imbalance amount and detailing the amount due in accordance with the following calculations.

(a) Cashout Price. The Cashout Price shall be determined on a daily and monthly basis. The cashout High and Low Common prices shall be determined by use of the highest and lowest daily price for the Month and the first seven Days of the subsequent Month as published in Platts Gas Daily "Daily Price Survey". The average Midpoint price shall be determined by the arithmetical average of Platts Gas Daily "Daily Price Survey" "Midpoint" price for the Month and the first seven days of the subsequent month. The Cashout Price for purposes of resolving imbalances shall be the average of the "Daily Price Survey" prices for the relevant month for the following pipeline areas:

Pipeline Receipt Area	"Daily Price Survey" Price
Perryville Hub to Texas Eastern interconnect	Columbia Gulf, mainline
Texas Eastern interconnect to Transco interconnect	Texas Eastern, ELA
Transco interconnect to Tennessee interconnect	Transco, zone 4
Tennessee interconnect to Florida Gas interconnect	Tennessee, La., Leg 500
Florida Gas interconnect to system terminus	Florida Gas, zone 3

The daily index prices will be posted on the LINK® System. All references to "Cashout Price" in these General Terms and Conditions refer to the "Midpoint" price contemplated in this Section 8.7(a), with the exception of this Section 8 (which refers to the "Midpoint" price only if the context so requires).

Cessation of Publications. If on any Day, the reported prices referenced above are not published, Transporter shall determine the relevant cashout prices using another similar publication selected by Transporter, in its reasonable judgment, that is broadly published and widely accepted within the natural gas industry as a reliable source for the quotation of Gas prices.

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(b) Imbalance Due Transporter. In the event a monthly imbalance is an Imbalance Due Transporter, Transporter shall charge Cashout Party for such excess Deliveries plus an allowance for fuel calculated by multiplying such excess Deliveries by the applicable Transporter's Use %. If a Cashout Party's monthly imbalance is less than or equal to 5%, the monthly cashout bill will be based on the average Midpoint price contemplated in Section 8.7(a). The Monthly System Imbalance will be calculated at the same time the initial cashout bill for that Month is generated. If a Cashout Party's Monthly Imbalance is greater than 5%, the monthly cashout bill will be based on the accumulated sum of the results of the formulas listed below such that, and until, the total Monthly Imbalance is fully accounted for:

Imbalance Level	Factor	Applicable Cashout Price
0% - = <5%	1.00	average Midpoint
> 5% - =<10%	1.10	(High Common x quantity > 5%) + level above
>10% - =<15%	1.20	(High Common x quantity >10%) + levels above
>15% - =<20%	1.30	(High Common x quantity >15%) + levels above
>20% - =<25%	1.40	(High Common x quantity >20%) + levels above
>25%	1.50	(High Common x quantity >25%) + levels above

For purposes of determining the appropriate cashout Factor, Cashout Party's imbalance level shall be determined by taking the lower of (a) the level of imbalance supplied pursuant to Section 24.2, or (b) the imbalance computed by comparing (i) the Deliveries at the Delivery Point and (ii) the Receipts at the Receipt Point and by dividing the amount of the excess Deliveries by the Receipts less the Transporter's Use. For OBA imbalances that are resolved pursuant to this Section 8, the calculation of cashout charges relating to excess Deliveries shall also include a Transportation imbalance charge, which shall be calculated by multiplying the excess Delivery quantity by the actual weighted average of all applicable Usage Rates owed on all quantities of Gas delivered during the Month to that OBA Party.

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(c) Imbalance Due Cashout Party. In the event of a Monthly Imbalance which is an Imbalance Due Cashout Party, Transporter shall make a cashout payment to Cashout Party reflecting such excess Receipts.

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If a Cashout Party's Monthly Imbalance is less than or equal to 5%, the monthly cashout bill will be based on the average Midpoint price contemplated in Section 8.7(a). If a Cashout Party's Monthly Imbalance is greater than 5%, the monthly cashout bill will be based on the accumulated sum of the results of the formulas listed below such that, and until, the total Monthly Imbalance is fully accounted for:

Imbalance Level	Factor	Applicable Cashout Price
0% - = <5%	1.00	average Midpoint
>5% - =<10%	.90	(Low Common x quantity > 5%) + level above
>10% - =<15%	.80	(Low Common x quantity >10%) + levels above
>15% - =<20%	.70	(Low Common x quantity >15%) + levels above
>20% - =<25%	.60	(Low Common x quantity >20%) + levels above
>25%	.50	(Low Common x quantity >25%) + levels above

For purposes of determining the appropriate cashout Factor, Cashout Party's imbalance level shall be determined by taking the lower of (a) the level of imbalance supplied pursuant to Section 24.2, or (b) the imbalance computed by comparing (i) the Deliveries at the Delivery Point and (ii) the Receipts at the Receipt Point and by dividing the excess Receipts by the total Receipts less Transporter's Use. For OBA imbalances that are resolved pursuant to this Section 8, the calculation of the amount due the Cashout Party relating to excess Receipts shall also include a Transportation imbalance credit, which shall be calculated by multiplying the excess Receipt quantity by the actual weighted average of all applicable Usage Rates owed on all quantities of Gas delivered during the Month to that OBA Party. Transporter shall have no responsibility for the distribution of funds beyond the initial distribution, in accordance with this resolutions procedure, to the Cashout Party.

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(d) A Cashout of Transportation Imbalances at prices above or below the average Midpoint price shall not occur if it has been determined that such Transportation Imbalances are due to Transporter's negligence. Additionally, a Cashout of Transportation Imbalances due to Imbalance Due Transporter quantities or Imbalance Due Cashout Party quantities shall be limited to the average Midpoint price if such imbalances occurred during circumstances of Force Majeure that directly affect the Transporter's or upstream or downstream facilities over which Gas is transported under the applicable Agreement, or during circumstances of Force Majeure that directly affect Shipper's facilities for the period until Shipper has an opportunity to adjust its nominations (Shipper shall give written notice within forty-eight (48) hours of such Force Majeure event), or were the direct result of an OFO issued to the Shipper or its supplier.

8.8 Cashout of Transportation Imbalances at Agreement Expiration. At the time of expiration of an Agreement, all Transportation Imbalances shall be resolved pursuant to the provisions of Section 8.7 above.

8.9 Annual System Cashout Mechanism. Transporter shall establish an annual mechanism to determine the costs of implementing this Cashout provision. Such mechanism shall calculate, on a system-wide basis, the annual gross balance (positive or negative) derived from the Cashout program, which will be accounted for and disposed of in accordance with Section 22.3 of the General Terms and Conditions.

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9. BILLING

9.1 Transporter shall render an invoice(s) to Shipper for each Month for (i) all Transportation Services provided pursuant to this Tariff during the preceding Month; and (ii) any other charges for which Shipper is liable under the Tariff or Shipper's other obligations. The Imbalance Statement shall be rendered prior to or with the transportation invoice(s), and the transportation invoice(s) shall be prepared on or before the 9th Business Day after the end of the Service Month. Rendered is defined as postmarked, time-stamped, and delivered to the designated site or designated as approved or final on LINK®. Shipper may choose on LINK® to be notified via e-mail when invoices are rendered. Prior Period Adjustment time limits shall be 6 Months from the date of the initial transportation invoice(s) with a 3-Month rebuttal period, excluding government-required rate changes. This standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard. Prior Period Adjustments shall be reported by production date, but do not have to be invoiced separately by production Month nor is each production Month a separate paper invoice page.

9.2 With respect to Cashout invoices, an Imbalance Statement and associated invoice shall be rendered in the second Month after the Monthly Transportation Imbalance occurs, which shall reflect the amount Due Transporter or a credit for the amount Due Cashout Party, as determined in Section 8 herein will be rendered with the Monthly Transportation invoice.

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9.3 Both Transporter and Shipper shall have the right to examine at any reasonable time the applicable records of the other to the extent necessary to verify the accuracy of any statement made under or pursuant to the provisions of the Agreement. Upon receipt of a request, the recipient will either send the relevant information to the requestor or will provide the requestor the right to review such information in the recipient's offices.

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10. PAYMENTS

10.1 All payments for invoices due to Transporter by Shipper shall be made by Shipper to a depository designated by Transporter via electronic funds transfers within ten (10) Days of the Day the invoice is rendered, (the "Payment Due Date"). Shipper shall submit any necessary supporting documentation with its payment except as provided below; Transporter shall apply payment per supporting documentation provided by Shipper, and if payment differs from the invoiced amount, remittance detail shall be provided with the payment except when payment is made by electronic funds transfer (EFT), in which case, the remittance detail is due within two Business Days of the payment date. Invoice number(s) shall be identified on all payments. If presentation of an invoice to Shipper is delayed after the 10th Day of the Month, the Payment Due Date shall be extended by an equal number of Days, unless Shipper is responsible for such delay.

10.2 Should Shipper fail to pay all of the amount of any invoice as herein provided, on or before the Payment Due Date, Shipper shall pay a charge for late payment which shall be included by Transporter on the next regular Monthly bill rendered to Shipper under this Section 10. Such charge for late payment shall be determined by multiplying (a) the unpaid portion of the invoice, by (b) the ratio of the number of Days from the Payment Due Date to the date of actual payment to 365 (366 in a leap year), by (c) the interest rate determined in accordance with Section 154.501(d) of FERC's regulations. If such failure to pay continues for 30 Days after the Payment Due Date, Transporter, in addition to any other remedy it may have under the relevant Agreement, may terminate such Agreement and suspend further delivery of Gas, provided Transporter provides Shipper and the Commission with 30 Days prior written notice of such termination and provided further such termination shall not be effective if, prior to the date of termination Shipper complies with the billing dispute procedure in Section 10.4 of the General Terms and Conditions of Transporter's Tariff.

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10.3 In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within 30 Days of the determination of the error; provided that any claim therefore shall have been made within 60 Days of discovery of such error and, in any event, within 6 Months from the date of the statement claimed to be in error. Billing errors shall be corrected as follows:

(a) Where Shipper has been overcharged and has paid the statement, in the event the overcharge is not the result of Transporter's negligence or bad faith, fraud or willful misconduct, the amount of the overpayment will be refunded to Shipper without interest provided the overpayment is refunded within 30 Days. Overpayments not refunded within 30 Days will be subject to interest charges at the interest rate determined in accordance with Section 154.501(d) of FERC's regulations from the date of the overpayment to the date of the refund. Where the refund is provided to Shipper by way of credit on a subsequent invoice rendered to Shipper by Transporter, the overpayment will be deemed to have been refunded on the date the credited invoice was received by Shipper.

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(b) Where Shipper has been undercharged by Transporter, Shipper will pay the amount of the undercharge without interest provided the undercharge is paid within 30 Days. Undercharge amounts not paid within 30 Days will be subject to interest charges at the interest rate determined in accordance with Section 154.501(d) of FERC's regulations from the date of the statement. Shipper shall have the right to review all records pertaining to its performance under Shipper's Agreement to verify the amount payable by Shipper to Transporter under the Agreement in any Month, so long as such review shall be completed within two years following the end of the calendar year in which such amount is payable. Such review shall be conducted during normal business hours, upon written request to Transporter and at Shippers' own expense.

10.4 If an invoice is in dispute, Shipper shall pay the portion not in dispute and provide documentation identifying the basis for the dispute. If Shipper in good faith:

(a) disputes the amount of any such bill or part thereof;

(b) pays to Transporter such amounts as it concedes to be correct;

(c) provides Transporter with a written notice including a full description of the reasons for the dispute, together with copies of supporting documents; and

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(d) at any time thereafter within 30 Days of a demand made by Transporter furnishes good and sufficient surety bond, guaranteeing payment to Transporter of the amount ultimately found due upon such bill after a final determination which may be reached either by agreement or judgement of the courts, as may be the case, then Transporter shall not be entitled to suspend further services because of such non-payment pursuant to Section 10.2 unless and until default be made in the conditions of such bond.

10.5 In the event that Shipper does not pay the full amount due Transporter in accordance with this Section 10, Transporter, without prejudice to any other rights or remedies it may have, shall have the right to withhold and set off payment of any amounts of monies due or owing by Transporter to Shipper, against any and all amounts or monies due or owing by Shipper to Transporter for Transportation Services provided.

10.6 Any payments received under this Section 10 shall first be applied to accrued interest, then to additional charges due, then to the previously outstanding principle, and lastly, to the most current principle due.

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11. POSSESSION OF GAS

Unless otherwise provided in the Agreement or applicable Rate Schedule, as between Transporter and Shipper, Shipper shall be deemed to be in exclusive control and possession of the Gas (i) prior to receipt by Transporter at the Receipt Point(s) and (ii) after delivery by Transporter at the Delivery Point(s); otherwise, Transporter shall be in exclusive control and possession of the Gas. The party which shall be in exclusive control and possession of the Gas shall be responsible for all injury or damage caused thereby to any third party except any injury or damage caused by Gas provided by Shipper that fails to conform with the specifications set forth in Section 3. In the absence of bad faith or willful misconduct on the part of Transporter, Shipper waives any and all claims and demands against Transporter, its officers, employees or agents, arising out of or in any way connected with (i) the quality, use or condition of the Gas after delivery from Transporter for the account of such Shipper, (ii) any losses or shrinkage of Gas during or resulting from Transportation hereunder, and (iii) all other claims and demands arising out of Transporter's performance of its duties hereunder.

12. RECEIPT AND DELIVERY POINT PRESSURE

12.1 All gas tendered by or on behalf of Shipper to Transporter will be delivered at Receipt Points at a pressure sufficient to enter Transporter's system up to Transporter's Maximum Allowable Operating Pressure.

12.2 Unless otherwise agreed to, Transporter will redeliver Gas at the Delivery Points nominated by Shipper at Transporter's prevailing line pressure of no less than 250 pounds per square inch, gauge pressure ("Minimum Delivery Pressure"). If Transporter and Shipper otherwise agree on the Minimum Delivery Pressure at a Delivery Point(s), it will be set forth on Exhibit B of the Agreement.

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13. OPERATIONAL FLOW ORDERS (OFOs)

13.1 Notification of Conditions that May Require the Issuance of an OFO or Action Alert: Transporter shall provide prior notice, via posting on LINK® and to affected Shippers and point operators through the affected party's choice of Electronic Delivery Mechanism(s), of upcoming events that may affect Transporter's pipeline system such as anticipated weather patterns or operational situations that may necessitate the issuance of an OFO pursuant to this Section 13.

13.2 Circumstances Warranting Issuance of an Operational Flow Order: Transporter shall have the right to issue Operational Flow Orders as specified in this Section 13 that require actions by Shippers/point operators in order (1) to alleviate conditions that threaten to impair Transporter's ability to provide reliable service, (2) to maintain pipeline operations at the pressures required to provide efficient and reliable service, (3) to have adequate Gas supplies in Transporter's system to receive and deliver Gas consistent with its firm Transportation Service obligations, (4) to maintain Transportation Service to all firm Shippers and for all firm Transportation Services, and (5) to maintain Transporter's system in balance for the foregoing purposes. Transporter shall lift any effective Operational Flow Order, promptly upon the cessation of operating conditions that caused the relevant system problem(s). Routine repairs and maintenance will not be used as a basis for issuing OFOs. Transporter will plan routine repairs and maintenance by scheduling such activities in advance.

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13.3 Voluntary Actions to be Taken to Avoid Issuance of an Operational Flow Order: Transporter shall, to the extent practicable, take all reasonable actions necessary to avoid issuing an Operational Flow Order. Such actions may include (1) working with point operators to temporarily adjust, by mutual agreement, receipts and/or deliveries at relevant Receipt Point(s) or Delivery Point(s), (2) working with Shippers/point operators to adjust, by mutual agreement, scheduled flows on Transporter's system, (3) issuing an Action Alert designed to mitigate the conditions which, if continued, would require the issuance of an Operational Flow Order, or (4) taking any other reasonable action designed to mitigate the system problem. After taking all such reasonable actions to avoid issuing an Operational Flow Order, Transporter will have the right to issue Operational Flow Orders, if necessary, in the circumstances described in Sections 13.2 and 13.7.

13.4 Applicability of Operational Flow Orders or Action Alerts: Transporter shall issue an Operational Flow Order or Action Alert as localized as is reasonably practicable based on Transporter's good faith judgment concerning the situations requiring remediation such that an Operational Flow Order or Action Alert will be directed (1) to Shippers/point operators causing the problem necessitating the Operational Flow Order or Action Alert or transporting Gas in the area of Transporter's system in which there is an operational problem, and (2) to those Shippers/point operators transporting Gas in the area of Transporter's system where action is required to correct the problem necessitating the Operational Flow Order or Action Alert. Transporter will tailor the Operational Flow Order or Action Alert to match the severity of the known or anticipated operational problem requiring remediation as more fully set forth in subsections 13.6 and 13.7.

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13.5 Notice: All Operational Flow Orders and Action Alerts will be issued via posting on LINK® to be followed by facsimile or telephone notification to the affected Shippers and point operators and notification to the affected parties through the affected party's choice of Electronic Delivery Mechanism(s). The Operational Flow Order/Action Alert will set forth (1) the time and date of issuance and effectiveness, (2) the actions a Shipper/point operator is required to take, (3) the time by which a Shipper/point operator must be in compliance with the Operational Flow Order/Action Alert, (4) the anticipated duration of the Operational Flow Order/Action Alert, and (5) any other terms that Transporter may reasonably require to ensure the effectiveness of the Operational Flow Order or Action Alert. Each Shipper and point operator must designate one or more persons, but not more than three persons, for Transporter to contact on operating matters at any time, on a 24-Hour a Day, 365-Day a year basis. Such contact persons must have adequate authority and expertise to deal with such operating matters. If Transporter cannot contact any Shipper/point operator because that Shipper/point operator has failed to designate a contact person or Shipper's/point operator's contact person is unavailable, Transporter shall not be responsible for any consequences that result from its subsequent actions taken to alleviate the system problem. Transporter, however, will make reasonable continuing efforts to notify the affected Shipper/point operator. In addition to the other information contemplated by this Section 13.5, such notice shall also include information about the status of operational variables that determine when an Operational Flow Order or Action Alert will begin and end, and Transporter shall post periodic updates of such information, promptly upon occurrence of any material change in the information. Transporter will post a notice on LINK® informing the Shipper/point operator when any Operational Flow Order or Action Alert in effect will be cancelled and specifying the factors that caused the Operational Flow Order or Action Alert to be issued and then lifted, to the extent such factors are known.

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(CONTINUED)

13.6 Action Alerts: In the event that, in Transporter's judgment, action is required to avoid a system integrity issue, Transporter may issue Action Alerts.

(a) Issuance of Action Alerts: Action Alerts will be noticed in accord with the procedures set forth in Section 13.5 and will be issued a minimum of four hours, or such shorter period of time as Transporter deems reasonable under the circumstances, prior to the required action by the Shipper/point operator.

(b) Required Actions: Action Alerts can be issued to effect any of the following:

(i) curtailment of interruptible services;

(ii) restrictions of receipts or deliveries at specific Receipt or Delivery Point(s) covered by an Operational Balancing Agreement to the aggregate MDQ under the firm Agreements whose Primary Receipt and/or Delivery Points are at the affected locations;

(iii) forced balancing such that point operators will be required to assure that nominations equal flows or that receipts and deliveries fall within the tolerance level designated in the Action Alert; and/or

(iv) any action required to maintain the integrity of Transporter's System.

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13.7 Operational Flow Orders: In the event that (1) Shipper/point operator does not respond to an Action Alert, or (2) the actions taken thereunder are insufficient to correct the system problem for which the Action Alert was issued, or (3) there is insufficient time to carry out the procedures with respect to Action Alerts, Transporter may periodically take unilateral action, including the curtailment of firm Transportation Service, to maintain the operational integrity of Transporter's system (or any portion thereof). For purposes of this Section 13.7, the operational integrity of Transporter's system shall encompass the integrity of the physical system and the preservation of physical assets and their performance, the overall operating performance of the entire physical system (or any portion thereof), and the maintenance (on a reliable and operationally sound basis) of total system deliverability and the quality of Gas delivered. Notice of an Operational Flow Order will be provided pursuant to and in accordance with Section 13.5 above.

13.8 Penalties: If a Shipper/point operator fails to comply with an Action Alert or Operational Flow Order, the Shipper/point operator shall be subject to a penalty as follows:

Action Alert penalty for each Dekatherm of Gas by which Shipper/point operator deviated from the requirements of the Action Alert equal to the product of 200% times the average Cashout price as determined pursuant to Section 8.7(a) of these General Terms and Conditions, for each Day that said Action Alert is in effect.

Operational Flow Order penalty for each Dekatherm of Gas by which Shipper/point operator deviated from the requirements of the Operational Flow Order equal to the product of 500% times the average Cashout price as determined pursuant to Section 8.7(a) of these General Terms and Conditions, for each Day that said Operational Flow Order is in effect.

Any penalty revenues received by Transporter as a result of the operation of Section 13.8 above will be credited pursuant to Section 23.4 of the General Terms and Conditions.

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13.9 Liability of Transporter: Transporter shall not be liable for any costs or damages incurred by any Shipper/point operator in complying with an Operational Flow Order. Transporter shall not be liable for any costs or damages that result from any interruption in Shipper's/point operator's service that is a result of a Shipper's/point operator's failure to comply promptly and fully with an Operational Flow Order. Shipper/point operator shall indemnify Transporter against any claims of liability, provided, however, that Transporter shall use reasonable efforts to minimize any such costs or damages.

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14. WARRANTY OF TITLE

14.1 This Article shall apply to all service unless otherwise provided in the applicable Rate Schedule or Agreement.

14.2 Shipper warrants for itself, its successors and assigns, that it will have, at the time of delivery of Gas hereunder, good title to the Gas it delivers, that the Gas it delivers hereunder shall be free and clear of all liens, encumbrances and claims whatsoever, that it will indemnify the Transporter and save it harmless from all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of any adverse claims of any and all persons to said Gas and/or to royalties, taxes, license fees, or charges thereon which are applicable for such delivery of Gas and that it will indemnify the Transporter and save it harmless from all taxes or assessments which may be levied and assessed upon such delivery and which are by law payable by and the obligation of the party making such delivery.

14.3 If Shipper's title or right to deliver Gas to be transported is questioned or involved in any action, Shipper shall not qualify for or shall be ineligible to continue to receive service until such time as Shipper's title or right to deliver is free from question; provided, however, Transporter shall allow Shipper to qualify for or continue receiving service under this Tariff if Shipper furnishes a bond satisfactory to Transporter.

14.4 Title to the Gas received by Transporter at the Receipt Point(s) shall not pass to Transporter, except that title to Gas delivered for Transporter's system fuel and uses and Gas lost and unaccounted for shall pass to Transporter upon delivery at the Receipt Point(s).

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15. FORCE MAJEURE

15.1 If either Transporter or Shipper fails to perform any obligations under an Agreement due to an event of Force Majeure, such failure shall be deemed not to be a breach of such obligations and neither party shall be liable in damages or otherwise as a result of an event of Force Majeure. A party that fails to perform any obligations under an Agreement where such failure is caused by an event of Force Majeure shall promptly remedy the cause of the Force Majeure insofar as it is reasonably able to do so.

15.2 Notwithstanding the above provisions, no event of Force Majeure shall:

(a) relieve any party from any obligation or obligations pursuant to an Agreement unless such party gives notice with reasonable promptness of such event to the other party;

(b) relieve any party from any obligation or obligations pursuant to an Agreement after the expiration of a reasonable period of time within which, by the use of its due diligence, such party could have remedied or overcome the consequences of such event of Force Majeure; or

(c) relieve either party from its obligations to make payments of amounts as provided in the applicable Rate Schedule, subject to any credit provided for in the applicable Rate Schedule.

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16. NOTICES

Except when the terms of this Tariff require or allow for communication via LINK® or EDM, any communication, notice, request, demand, statement, or bill provided for in the Tariff or in an Agreement or OBA, or any notice which either Transporter or Shipper may desire to give to the other, shall be in writing and shall be considered as duly presented, rendered, or delivered when mailed by either post-paid registered or ordinary mail or when sent by telecopy, telex, express mail service, or such other method mutually agreed upon between the parties. The material so sent shall be addressed to the pertinent party at its last known post office address, or at such other address as either party may designate.

17. MODIFICATION

No modification of the terms and provisions of an Agreement shall be made except by the execution of written contracts.

18. NON-WAIVER AND FUTURE DEFAULT

No waiver by either Transporter or Shipper of any one or more defaults by the other in the performance of any provisions of the Agreement shall operate or be construed as a waiver of any future default or defaults, whether of a like or of a different character.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

19. SCHEDULES AND CONTRACTS SUBJECT TO REGULATION

This Tariff, including these General Terms and Conditions and the respective obligations of the parties under an Agreement, are subject to valid laws, orders, rules, and regulations of duly constituted authorities having jurisdiction and are subject to change from time to time by addition, amendment, or substitution as provided by law.

20. OPERATIONAL BALANCING AGREEMENTS ("OBAs")

20.1 For the purposes of minimizing operational conflicts between various natural gas facilities with respect to the delivery of gas to and from Transporter's facilities, Transporter may negotiate and execute on a not-unduly discriminatory basis mutually agreeable OBAs with appropriate parties that operate natural gas facilities interconnecting with Transporter's system (any such party will be referred to herein as the "OBA Party"). Transporter must enter into OBAs at all points of interconnection between its system and the system of another interstate or intrastate pipeline. Such OBAs shall specify the Gas custody transfer procedures to be followed by Transporter and the OBA Party for the confirmation of scheduled quantities to be received by Transporter at Receipt Point(s) and delivered by Transporter at Delivery Point(s). Such OBA will provide that any variance between actual quantities and scheduled quantities at the point where the OBA is in place for any Day shall be resolved pursuant to the terms of the OBA.

To facilitate such determination of variances on a timely basis, Transporter and the OBA Party will agree in the OBA on necessary measurement and accounting procedures. Transporter shall post on LINK® those Receipt Point(s) and Delivery Point(s) at which an OBA is in effect.

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20.2 Transporter shall have no obligation to negotiate and execute OBAs with any OBA Party that:

(a) is not creditworthy as determined pursuant to Section 27 of the GT&C; for purposes of such provision, references to Shipper shall refer to the OBA Party;

(b) does not maintain dispatching operations which are staffed on a continuous around-the-clock basis every day of the year;

(c) would cause the level of regulation which Transporter is subject to prior to the execution of the applicable OBA to increase; or

(d) does not commit to timely determination of variances based on reasonable available measurement technology; or

(e) has not demonstrated operational consistency commensurate with the OBA relationship over a minimum period of three years.

20.3 If Receipt or Delivery Point Operators have not executed an OBA with Transporter as described in Section 20.1, then any variance between actual quantities and scheduled quantities for any Day for that Receipt or Delivery Point shall be cumulated for the month for the Shipper(s) responsible for the imbalance, and such monthly imbalances will be subject to the cashout of monthly imbalances as set forth in Section 8 herein.

20.4 Resolution of OBA Imbalance: Transporter and the OBA Party shall resolve any imbalances in accordance with the procedures set forth in the OBA. Unless otherwise agreed, OBA imbalances shall be resolved on a monthly basis by cashout mechanism.

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20.5 Nothing in this Section 20 nor any executed OBA shall limit Transporter's rights to take action as may be required to adjust receipts and deliveries under any Agreement to reflect actual experience or to alleviate conditions which threaten the integrity of Transporter's system, including maintenance of service to higher priority Shippers and/or services.

20.6 Form of OBA Agreement. A Form of OBA Agreement is displayed on LINK® for informational purposes.

21. NEW FACILITIES POLICY

21.1 Unless otherwise mutually agreed to by the parties, Transporter shall not be required to own, construct and install any facilities to perform any service requested by a Shipper under this Tariff. In the event Transporter agrees to own, construct and install facilities to perform services requested including, but not limited to, hot tap, side valve, measurement, Gas supply lateral lines, looping and/or compression facilities, Transporter shall do so on a not unduly discriminatory basis. Shipper shall reimburse Transporter (a) for the costs of such facilities installed by Transporter to receive, measure, transport or deliver natural gas for Shipper's account and (b) for any and all filings and approval fees required in connection with such construction that Transporter is obligated to pay to the Commission or any other governmental authority having jurisdiction. Nothing in this policy statement shall require Transporter to file an application for a certificate of public convenience and necessity under Section 7 (c) of the Natural Gas Act. Nothing in this policy statement, further, shall prevent Transporter from contesting an application for service filed pursuant to Section 7 (a) of the Natural Gas Act. Transporter reserves the right to seek a waiver of the policy set forth herein, for good cause shown.

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21.2 Transporter may waive from time to time, at its discretion, all or a portion of the monetary reimbursement requirement set forth in Section 21.1 if it determines that construction of the facilities would be economic to Transporter, based on Shipper assurance of Transportation throughput through the proposed facilities and other matters, as described below. All requests for waiver shall be handled by Transporter in a manner which is not unduly discriminatory. For purposes of determining whether a project is economic, Transporter will evaluate projects on the basis of various economic criteria, which may include, without limitation, the estimated Transportation throughput, cost of the facilities, operating, maintenance, administrative and general expenses attributable to the facilities, the system net revenues Transporter estimates will be generated subsequent to such construction, and the availability of capital funds on terms and conditions acceptable to Transporter. In estimating the system net revenues to be generated, Transporter will evaluate the existence of capacity limitations of the existing facilities, the marketability of the capacity, the location of the markets, the nature of the Transportation service, and other factors which impact the utilization of Transporter's system.

21.3 Any monetary reimbursement due Transporter by Shipper pursuant to this Section 21 shall be due and payable to Transporter prior to Transporter's commencement of construction of facilities to be constructed unless otherwise agreed by Transporter and within ten (10) Days of receipt by Shipper of Transporter's invoice(s) for same; provided, however, subject to Transporter's written consent, such monetary reimbursement, plus carrying charges thereon, may be amortized over a mutually agreeable period not to exceed the primary contract term of any Agreement for service between Transporter and Shipper. Carrying charges shall be computed utilizing interest factors acceptable to both Transporter and Shipper. Unless Transporter and Shipper otherwise agree on interest factors for computing the carrying charges for new facilities, the interest rates determined by the Commission under Section 154.501(d) of the Commission's regulations shall apply.

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21.4 In order to maintain and expand service and utilization of Transporter's system, Transporter may negotiate Agreements with Shippers in connection with which Transporter could make a contribution in aid of construction (CIAC) to the Shipper. The Shipper would use such funds to assist in the development of its natural gas related facilities. For any newly agreed to CIAC, Transporter will post on LINK® for a period of thirty (30) days (1) the amount of the CIAC, (2) the name of the Shipper receiving the CIAC, and (3) the economic feasibility of the CIAC. Such CIACs are includible in Transporter's jurisdictional rate base and amortizable. All CIACs entered into pursuant to this provision shall be subject to review and challenge by the Commission and all parties in a general rate case requesting inclusion of such costs.

22. PERIODIC RATE ADJUSTMENTS

Transporter and Shipper recognize that Transporter will from time to time experience changes in costs related to providing service under this Tariff, including, but not limited to, changes in the cost of labor, benefits, materials and supplies, taxes, required rate of return, costs associated with the resolution of past disputes or outstanding uncertainties concerning amounts owed by Transporter or Shipper or attributable to Transporter or Shipper, and costs generated by decisions of the Commission, the courts or by an arbitration panel or other body having jurisdiction over Transporter. Transporter and Shipper further recognize that it may be appropriate, equitable and consistent with cost responsibility to allocate such costs among Shippers based on or taking into account past period factors, such as contract demand levels, throughput or other factors related to a prior period of time. Shipper agrees that Transporter shall have the right from time to time to make rate change filings which may include such costs and utilize an allocation methodology based in whole or in part on factors related to past periods. Shipper shall have the right to intervene and protest any such filing.

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22.1 Federal Energy Regulatory Commission Annual Charge Adjustment.

(a) The purpose of this Section 22.1 is to establish an Annual Charge Adjustment ("ACA") as permitted by Section 154.402 of the Commission's Regulations to permit Transporter to recover from its Shippers all annual charges assessed it by the Commission under Part 382 of the Commission's Regulations.

(b) Applicable Rate Schedules: The ACA as set forth in the Statement of Rates for Transportation of Natural Gas of this Tariff, is applicable to Transporter's Rate Schedules FTS and ITS.

(c) Filing Procedure. Proposed changes in the ACA shall be filed by Transporter at least thirty (30) Days prior to the proposed effective date unless, for good cause shown, lesser periods are allowed by valid Commission Order. The proposed effective date of the filings shall be October 1 of each calendar year. Any such filing shall not become effective until it becomes effective without suspension or refund obligation.

(d) Remittance to the Commission. Transporter shall remit to the Commission, not later than forty-five (45) Days after receipt of the Annual Charges Billing, the Total Annual Charge stated on such billing.

(e) Basics of the Annual Charge Adjustment. The Rate Schedules specified in Section 22.1(b) hereof shall include an increment for an Annual Charge Adjustment for costs specified in Section 22.1(a), above. Such adjustment shall be the billable charge factor from the Commission, adjusted to the Company's pressure base and heating value, if required, which is stated in the Commission's Annual Charges Billing. The Annual Charge Adjustment shall be reflected in the Statement of Rates for Transportation of Natural Gas of this Tariff.

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22.2 Transporter's Use.

(a) The initial Transporter's Use (%) will be calculated based upon appropriate engineering principles. After one year of operation and each June 1 thereafter commencing in 2009, Transporter's Use (%) will be redetermined by dividing Transporter's projection for the next 12 Months beginning June 1 of fuel usage and any lost and unaccounted-for gas by Transporter's projection of applicable deliveries for the account of Shippers for the next 12 Months beginning June 1. This percentage will go into effect on June 1. Transporter may file interim proposals between annual filings subject to approval by the Commission.

(b) Pursuant to Section 22.3, Transporter shall maintain a separate System Balancing Adjustment account. This account shall be credited for all sales of excess fuel collected under Transporter's Use, debited for all purchases for Transporter's Use and further adjusted for the operational activities enumerated in Section 22.3(a).

22.3. System Balancing Adjustment. In order to maintain an operational system balance on its system, Transporter will calculate a system balancing adjustment ("SBA") charge.

(a) Transporter's SBA balance shall be the sum of:

(1) The net annual system cashout balance determined in accordance with Section 8 of the General Terms and Conditions and OBA cashouts;

(2) The net Transporter's Use Adjustment balance, determined in accordance with Section 22.2 of the General Terms and Conditions;

(3) Penalty revenues credited pursuant to Sections 23.1(a), 23.1(b), 23.2, and 23.3 of the General Terms and Conditions; and

(4) Any other account balance as may be approved by the FERC.

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(b) The net SBA balance determined in Section 22.3(a), through January 31 of the year in which the filing pursuant to Section 22.3(c) is made will be refunded or recovered from Shipper pursuant to the procedures in this Section 22.3. Upon determining the net SBA balance at the end of the accumulation period, Transporter shall calculate surcharges or refunds designed to allocate such balance to Shippers based upon each Shipper's actual throughput during the twelve-month accumulation period. A Shipper's net debit or credit for the accumulation period shall be due and payable sixty (60) Days after the Commission's acceptance of the filing pursuant to Section 22.3(c). Notwithstanding the immediately preceding sentence, if the net SBA balance results in a surcharge/debit, each Shipper who is allocated a surcharge/debit shall have the right by providing notice to Transporter within the sixty (60)-Day period to elect to pay the surcharge/debit ratably over the twelve (12)-Month period, commencing with the first Day of the first calendar month following the last Day of the sixty (60)-Day period, with interest calculated for each payment from the end of the sixty (60)-Day period until the payment is made (at the rate set forth in Section 154.501(d) of the Commission's regulations).

(c) Transporter shall file on May 1 of each year and each year thereafter, to establish the SBA refund or surcharge determined pursuant to the procedures in this Section 22.3.

23. PENALTIES AND PENALTY CREDITING MECHANISM

23.1 Rate Schedule PALS penalties.

(a) Penalty for PALS Non-compliance
In the event that a Shipper incurs a penalty pursuant to Section 4.1(b) of Rate Schedule PALS, which section is applicable if a Shipper does not comply with Transporter's notice given pursuant to Section 4.1(a) of Rate Schedule PALS to either remove Park service quantities or to return Loan service quantities, Transporter shall credit the penalty revenue, net of costs, to the System Balancing Adjustment, Section 22.3 of the General Terms and Conditions. Any penalty revenue credited to the System Balancing Adjustment

pursuant to this section shall include interest calculated in accordance with Section 154.501 of the Commission's regulations.

(b) Balances Remaining Upon PALS Contract Termination
In the event that Transporter receives penalty revenue from a PALS Shipper as the result of the application of Section 4.2 of Rate Schedule PALS to such PALS Shipper's unresolved balance, Transporter shall credit the penalty revenue received, net of costs, to the System Balancing Adjustment, Section 22.3 of the General Terms and Conditions. Any penalty revenue credited to the System Balancing Adjustment pursuant to this section shall include interest calculated in accordance with Section 154.501 of the Commission's regulations.

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23.2 Trespass Gas

In the event that Transporter receives penalty revenue from a Shipper as the result of the application of Section 7.3 (Trespass Gas) of the General Terms and Conditions, Transporter shall credit the penalty revenue received, net of costs, to the System Balancing Adjustment, Section 22.3 of the General Terms and Conditions. Any penalty revenue credited to the System Balancing Adjustment pursuant to this section shall include interest calculated in accordance with Section 154.501 of the Commission's regulations.

23.3 Conversion of Gas

In the event that Transporter receives penalty revenue from a Shipper as the result of the application of Section 7.4 (Conversion of Gas) of the General Terms and Conditions, Transporter shall credit the penalty revenue received, net of costs, to the System Balancing Adjustment, Section 22.3 of the General Terms and Conditions. Any penalty revenue credited to the System Balancing Adjustment pursuant to this section shall include interest calculated in accordance with Section 154.501 of the Commission's regulations.

23.4 Action Alert/Operational Flow Order Penalties

Any penalty revenue collected by Transporter pursuant to Section 13.8 of the General Terms and Conditions will be credited, net of costs, to any firm or interruptible Shipper that did not incur penalties pursuant to Section 13.8 of the General Terms and Conditions in the Month for which penalty revenues were received ("Non-Offending Shipper"), based on the ratio of the actual quantities taken by the Non-Offending Shipper to the actual quantities taken by all Non-Offending Shippers in such Month. Such credits shall be made within 90 days following each anniversary of the initial in-service date of Transporter's system and shall include interest at the rate determined in accordance with Section 154.501 of FERC's regulations.

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24. ELECTRONIC COMMUNICATION

24.1. System Description

(a) Transporter provides for interactive electronic communications with its Shippers and other parties through the LINK® Customer Interface System (hereinafter called the "LINK® System"). The LINK® System shall be available on a nondiscriminatory basis to any party (such party is referred to herein as the "LINK® System Subscriber"), provided that such party (i) has a Valid Service Agreement or has executed a LINK® System Agreement, and (ii) has designated a Local Security Administrator, who shall have the responsibilities set forth in Section 24.3 below, by completing the Local Security Administrator Form, as such form is amended from time to time and posted on the LINK® System. For purposes of this Section 24 and the form of LINK® System Agreement only, a "Valid Service Agreement" includes any service agreement pursuant to any of Transporter's Rate Schedules and/or a capacity release umbrella agreement. Parties with a Valid Service Agreement are not required to execute a LINK® System Agreement in conjunction therewith. Transporter will allow a Shipper that does not have a Valid Service Agreement or an executed LINK® System Agreement to submit a request for service pursuant to one of Transporter's Rate Schedules online via the LINK® System, and, if applicable, to execute the resulting Service Agreement online via the LINK® System. There is no requirement that a LINK® System Subscriber must be a party that has executed a Valid Service Agreement. Any party desiring access to the LINK® System for purposes other than submitting a request for service or executing a resulting Service Agreement that has not executed a Valid Service Agreement, however, must execute a LINK® System Agreement or have on file a valid LINK® System Agreement in accordance with the terms of this tariff and the form of LINK® System Agreement contained herein. By accessing the LINK® System, all LINK® System Subscribers agree to comply

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with the procedures for access to and use of the LINK® System as set forth in this Section 24. All LINK® System Subscribers must complete and submit to Transporter the Local Security Administrator Designation Form, the Contact Information Form, and any other applicable LINK® forms, as updated from time to time and posted on the LINK® System. In addition, LINK® System Subscriber must complete and submit to Transporter the Designation of Agency Form and/or the Designation of Affiliated Companies Form, if applicable, as updated from time to time and posted on the LINK® System. In the event Shipper desires to change any of the information provided by Shipper on such form(s), Shipper shall be required to promptly provide Transporter with the updated information by submitting revised form(s) to Transporter. Such revised form(s) shall supersede in its entirety any form(s) previously submitted to Transporter. Transporter reserves the right to implement, to contract for or obtain a license for enhancements to the LINK® System at its sole discretion; provided however, all such enhancements when fully operational shall be available to all LINK® System Subscribers. Transporter will exercise due diligence to ensure the LINK® System operates correctly and will provide timely and non-discriminatory access to on-line LINK® System help features and to any information available on the LINK® System that LINK® System Subscriber is entitled to access.

(b) The LINK® System provides on-line help, a search function that permits a LINK® System Subscriber to locate information concerning a specific transaction, and menus that permit LINK® System Subscribers to separately access notices of available capacity, records in the transportation request log, and standards of conduct information. The LINK® System will permit a LINK® System Subscriber to electronically download information on transactions from the LINK® System and to separate extremely large documents into smaller files prior to such download. Transporter shall maintain and retain daily back-up records of the information displayed on the LINK® System and the web site and through electronic data interchange for three years and shall permit LINK® System Subscriber to review those records upon request. Completed

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transactions will remain on the LINK® System for at least ninety days after completion and will then be archived. Archived information will be made available by Transporter if possible within two weeks after receipt of a Shipper's request for such information. Information on the most recent entries will appear ahead of older information.

(c) Shippers' Notices pursuant to Section 25 of the General Terms and Conditions shall be submitted electronically and, in addition, posted electronically by the Shipper via the LINK® System. Electronic communications may also be transmitted, where applicable, via electronic data interchange, which will be available on a nondiscriminatory basis to any LINK® System Subscriber, provided such LINK® System Subscriber has entered into a trading partner agreement with Transporter, in addition to the agreements specified in Section 24.1(a) above. Specifically, a LINK® System Subscriber has the option of utilizing the LINK® System for purposes of: (a) requesting service under Transporter's Rate Schedules set forth in Transporter's FERC Gas Tariff; (b) executing, tracking and amending certain Service Agreements under Transporter's rate schedules set forth in Transporter's FERC Gas Tariff; (c) providing nominations and viewing allocations and operational imbalances under all rate schedules as a Shipper of Transporter pursuant to the applicable rate schedule and the General Terms and Conditions; (d) exercising its rights as a Shipper of Transporter pursuant to Section 25 of the General Terms and Conditions or submitting a bid as a Replacement Shipper of Transporter under such section; (e) exercising its rights as a Shipper of Transporter pursuant to Section 25 of the General Terms and Conditions (which, if submitted utilizing the LINK® System, will be posted at that time) or submitting a bid as a Replacement or Prearranged Shipper of Transporter pursuant to such section, or posting a Capacity Request for capacity release pursuant to such section; (f) viewing and downloading operational data for any gas flow day on the second subsequent gas flow day; (g) viewing Transporter's notice of an OFO as contemplated by Section 13 of the General Terms and Conditions; (h) effectuating Imbalance Netting and Trading

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pursuant to Sections 8.3 and 8.4 of the General Terms and Conditions; (i) requesting a discount of the maximum recourse rate(s) for service under Transporter's Open-access Rate Schedules or viewing such discounts previously granted; and (j) such other functions as may be available on the LINK® System from time to time.

24.2 Information. Transporter shall post at least four times a day on the LINK® System and the web site information relevant to the availability of firm and interruptible capacity at Receipt Points, on the mainline, and at Delivery Points. The LINK® System and the web site will indicate whether the capacity is available from Transporter directly or through Transporter's capacity release mechanism as set forth in Section 25 of the General Terms and Conditions. The LINK® System and the web site shall provide the best available information about imbalances on an hourly and a daily basis. The LINK® System and the web site also include information allowed or required to be posted thereon by other provisions of the tariff including Section 25, information that Transporter is required to post pursuant to the Commission's regulations, or other information Transporter chooses to post in furtherance of the operation of its system. Transporter shall maintain both in written form and on the LINK® System a Master Receipt/Delivery Point List containing the following information for each point. Such information shall be updated promptly whenever Receipt Point(s) or Delivery Point(s) are added to Transporter's system.

(1) Name of the Point;
(2) Meter Number of the Point;
(3) Location (legal description) of the Point;
(4) Operator name and phone number to the extent available; and
(5) Whether there is an operational balancing agreement in effect at the Point.

24.3. Local Security Administrators

(a) LINK® System Subscriber shall designate one or more persons to perform certain security functions on the LINK® System ("Local Security Administrator") by completing and submitting the Local

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Security Administrator Designation Form, as such form is amended from time to time and posted on the LINK® System. The Local Security Administrator shall, via the LINK® System, be responsible for (1) identifying those persons who are duly authorized by LINK® System Subscriber to use the LINK® System to perform one or more of the functions available on the LINK® System ("LINK® System User"); (2) providing LINK® System Users with individualized USERIDs and passwords; (3) maintaining LINK® System Users' account information; (4) adding and terminating LINK® System Users immediately upon a change in status requiring such addition or termination; (5) creating and modifying security rights for LINK® System Users; and (6) ensuring that USERIDs are used only as appropriate and as contemplated by these General Terms and Conditions and the LINK® System Agreement.

(b) Transporter shall be entitled to rely upon the representation of LINK® System Subscriber's Local Security Administrator that the LINK® System User(s) identified by the Local Security Administrator may (i) transmit information to Transporter; (ii) view information posted on the LINK® System; and/or (iii) perform the LINK® System contracting function in accordance with the rights granted by Local Security Administrator.

24.4 Authorized Use of LINK® System; Confidentiality

(a) LINK® System Subscriber shall complete and submit a Contact Information Form as such form is amended from time to time and posted on the LINK® System. LINK® System Subscriber shall be required to keep such form current by submitting a new form as such information changes. Such revised form shall supersede in its entirety any form previously submitted to Transporter.

(b) LINK® System Subscriber shall not disclose to persons other than Local Security Administrator and LINK® System Users that are employed by LINK® System Subscriber, or properly designated affiliates or agents of LINK® System Subscriber, and shall otherwise keep confidential, all USERIDs and passwords issued by Local Security Administrator. In addition, LINK® System Subscriber shall cause Local Security Administrator and LINK®

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System User(s) to refrain from disclosing to any other person, whether or not employed by LINK® System Subscriber, and shall otherwise keep confidential, the individualized USERID and password issued to each such LINK® System User.

(c) LINK® System Subscriber shall be solely responsible for any unauthorized or otherwise improper use of USERIDs and passwords issued by or for its Local Security Administrator, including, but not limited to, the use of such USERIDs and passwords by LINK® System Users who are not within LINK® System Subscriber's employment or control.

(d) Transporter reserves the right to disable for due cause any USERID issued to any LINK® System User. Transporter shall give prior notice to LINK® System User and Local Security Administrator and allow such Local Security Administrator a reasonable amount of time to respond before disabling any such USERID. In the event Local Security Administrator fails to adequately respond within the time period established in Transporter's notice, Transporter shall have the right to disable such USERID without further notice. In addition, upon thirty (30) days prior notice to the LINK® System User and the Local Security Administrator, Transporter will disable any USERID that has not been used to access the LINK® System for six (6) consecutive months.

(e) LINK® System Subscriber shall immediately notify Transporter, by e-mail to link-help@duke-energy.com, of the need or desire to change or delete a Local Security Administrator of LINK® System Subscriber. In addition, LINK® System Subscriber must complete a Local Security Administrator Designation Form as required in Section 24.3(a) above in order to document and allow such change or deletion to take place. LINK® System Subscriber shall be solely responsible for any unauthorized actions of Local Security Administrator due to LINK® System Subscriber's failure to so notify Transporter of the need to change or delete such Local Security Administrator.

(f) Transporter warrants that, without the express consent of LINK® System Subscriber or as otherwise provided in this FERC Gas Tariff, no Transporter employee or agent will disclose to any

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third party any non-public information regarding research performed through the use of the LINK® System by LINK® System Subscriber.

24.5 LINK® System Subscriber; Affiliated Companies

(a) If LINK® System Subscriber belongs to a group of affiliated companies and requires LINK® System access on behalf of one or more of said affiliates, LINK® System Subscriber shall, or shall cause one of the affiliates of LINK® System Subscriber to, complete and submit to Transporter a Designation of Affiliated Companies Form, as such form is amended from time to time and posted on the LINK® System. LINK® System Subscriber shall, or shall cause one of its properly designated affiliates to keep such form current by submitting to Transporter an updated form when such information changes. Such revised form shall supersede in its entirety any form(s) previously submitted to Transporter. LINK® System Subscriber warrants that access consistent with any Designation of Affiliated Companies Form submitted by LINK® System Subscriber or one of its affiliates is appropriate and authorized. Determining the propriety of such access is the responsibility of LINK® System Subscriber and/or its affiliates, but Transporter reserves the right to reject such Designation of Affiliated Companies Form if it determines that granting such designation would violate any contractual, legal, or regulatory responsibility of Transporter.

(b) In order for LINK® System Users of LINK® System Subscriber to access the LINK® System on behalf of LINK® System Subscriber's affiliates identified on the Designation of Affiliated Companies Form, LINK® System Subscriber and each affiliate of LINK® System Subscriber identified on the Designation of Affiliated Companies Form must either be: (1) a Shipper with a Valid Service Agreement as defined in Section 24.1(a) of these GT&C, or (2) a LINK® System Subscriber under a LINK® System Agreement.

24.6. LINK® System Subscriber; Agency

(a) If LINK® System Subscriber desires to designate one or more persons or entities to act as an agent on behalf of LINK®

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System Subscriber ("Agent"), LINK® System Subscriber must complete and submit to Transporter the Designation of Agency Form, as such form is amended from time to time and posted on the LINK® System, for each such Agent, specifying which rights are granted to each Agent. Transporter may require that LINK® System Subscriber provide additional documentation to confirm that LINK® System Subscriber desires Agent to act on its behalf.

(b) In order for LINK® System Users of Agent to access the LINK® System on behalf of LINK® System Subscriber, such Agent must either be: (1) a Shipper with a Valid Service Agreement as defined in Section 24.1(a) of these GT&C, or (2) a LINK® System Subscriber under a LINK® System Agreement.

(c) Transporter may fully rely upon all communications received from and direction given by Agent with respect to all actions indicated in the Designation of Agency Form for which Agent is authorized to act on behalf of LINK® System Subscriber. Transporter may grant Agent access to LINK® System Subscriber's data contained in the LINK® System as necessary to perform the functions identified in the Designation of Agency Form. Transporter may accept and fully rely upon a Designation of Agency Form that has been properly executed by LINK® System Subscriber and Agent. LINK® System Subscriber will defend, indemnify and hold harmless Transporter from and against any and all claims, demands, liabilities and/or actions, and/or any and all resulting loss, costs, damages, and/or expenses (including court costs and reasonable attorney's fees) of any nature whatsoever, that may be asserted against or imposed upon Transporter by any party associated with Transporter's reliance on a Designation of Agency Form provided pursuant to this Section 24.6.

(d) The rights specified on the Designation of Agency Form having the latest commencement date shall supersede all prior rights granted by LINK® System Subscriber to Agent identified on such Designation of Agency Form. In no event can an agency right granted to one Agent be simultaneously granted to another Agent. It is the obligation of the LINK® System Subscriber to notify Transporter when an Agency relationship changes or

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terminates, either by specifying a termination date on the Designation of Agency Form or by providing Transporter with a properly executed superseding Designation of Agency Form. LINK® System Subscriber must update and re-submit to Transporter the Designation of Agency Form on an annual basis. Transporter shall disable the USERIDs of all LINK® System Users of Agent pertaining to access granted by LINK® System Subscriber pursuant to the Designation of Agency Form if LINK® System Subscriber does not update and re-submit the Designation of Agency Form on an annual basis.

(e) Agent is authorized to act on behalf of LINK® System Subscriber under any or all of LINK® System Subscriber's contracts with Transporter as effective from time to time, or with respect to any or all meter locations as available from time to time, respectively, as specified in the Designation of Agency Form, until LINK® System Subscriber properly notifies Transporter that the agency relationship is terminated or superseded in accordance with Section 24.6(d). The Designation of Agency Form does not provide for an assignment of the rights and obligations of any contract between Transporter and LINK® System Subscriber.

24.7. Liability

(a) Transporter shall not be liable to LINK® System Subscriber nor any other party in damages for any act, omission or circumstance related to the LINK® System occasioned by or in consequence of an event of Force Majeure as defined in Section 15 of these General Terms and Conditions, that is not within the control of Transporter and which by the exercise of due diligence Transporter is unable to prevent or overcome. To the extent the information displayed on the LINK® System is originated solely by Transporter and such information is subsequently determined to be inaccurate, LINK® System Subscriber shall not be subject to any penalties otherwise collectable by Transporter based on Shipper conduct attributable to such inaccuracy during the period the inaccurate information was displayed on the LINK® System.

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(b) LINK® System Subscriber shall defend, indemnify and hold harmless Transporter from and against any and all claims, demands and/or actions, and/or any and all resulting loss, costs, damages, and/or expenses (including court costs and reasonable attorney's fees) of any nature whatsoever, that may be asserted against or imposed upon Transporter by any party as a result of the unauthorized or otherwise improper use of any USERID and/or password issued to or by LINK® System Subscriber and/or Local Security Administrator or any other unauthorized or improper use of the LINK® System by any LINK® System User or LINK® System Subscriber unless such improper use is the result of Transporter's negligence or willful misconduct, including, but not limited to, distribution of USERIDs or passwords to persons that are not employed by, or agents or affiliates of, LINK® System Subscriber.

24.8 Electronic Mail (E-mail) Notification. For system-wide notices of general applicability, any provisions of this FERC Gas Tariff requiring that these matters be written or in writing are satisfied by Transporter utilizing electronic transmission through the LINK® System in accordance with the procedures for utilization of the LINK® System or through electronic data interchange as provided for in Commission-approved or permitted data sets. Critical system-wide notices will be in a separate category from notices that are not critical. Transporter will use electronic mail (e-mail) in order to facilitate certain notifications to Shippers as required by this FERC Gas Tariff. Shipper shall provide Transporter with at least one e-mail address to which these notifications can be sent, and shall be responsible for updating such information as necessary. In addition to the requirement specified in Sections 6 and 13 of these General Terms and Conditions to post notices on the LINK® System, Transporter shall provide such notifications via e-mail communication to those Shippers that have provided such e-mail address information and have requested, via the LINK® System, e-mail notification of critical notices issued by Transporter. Shipper shall be responsible for providing accurate e-mail notification information to Transporter, including timely updates to such information as necessary. All other provisions, including service agreement-specific notices, requiring items or information to be written or in writing remain unchanged unless otherwise agreed by Transporter and Shipper.

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24.9. Rights to LINK® System. Transporter or an affiliate of Transporter is the exclusive proprietor of the programming that generates the LINK® System and of all the copyrights and proprietary interests therein, except insofar as any third party (whose materials are made available in the files of the LINK® System under license to Transporter or an affiliate of Transporter) possesses a copyright or proprietary interest in such materials, but not of the files of and the information displayed on the LINK® System. A LINK® System Subscriber will not by virtue of this Section 24 or the executed LINK® System Agreement acquire any proprietary interests in the programming that generates the LINK® System.

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25. CAPACITY RELEASE PROVISIONS

This section sets forth the terms and conditions that are applicable to the release of firm entitlements under various services that are provided pursuant to this Tariff.

25.1 Procedure. Capacity released shall be subject to the terms and conditions of this Section 25.1.

(a) Eligibility. Any Shipper ("Releasing Shipper") under Rate Schedule FTS of this Tariff, shall be entitled, subject to the terms and conditions of this Section 25.1, to release any or all of its firm Transportation entitlements held under an Agreement but only to the extent that the capacity so released is acquired by another Shipper ("Replacement Shipper") pursuant to the provisions of this Section 25.1. Any such release shall result in a temporary suspension of the Releasing Shipper's right to use the released firm entitlements.

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(b) Released Capacity shall be made available on a basis that is not unduly discriminatory, and any Replacement Shipper shall be entitled to acquire Releasing Shipper's capacity subject to the terms and conditions under this Section 25.1, provided the Replacement Shipper meets all provisions governing eligibility under this Tariff in a timely manner. A Replacement Shipper shall be entitled to release acquired capacity to another Replacement Shipper, subject to the requirement that the original Replacement Shipper satisfies all of the provisions of this Section 25.1 as if such Replacement Shipper were a Releasing Shipper, and the new Replacement Shipper meets all provisions governing eligibility under this Tariff in a timely manner, provided, however, that a Replacement Shipper that acquired released capacity through a volumetric bid shall not be entitled to re-release that capacity.

(c) Term. Any release under this Section 25 shall not extend beyond the expiration of the initial primary term of the Agreement that is released.

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(d) Recall / Reput Rights.

(1) Recall Provisions.

Releasing Shipper's rights to recall capacity on a full day or partial day basis shall be stated clearly in Shipper's Notice. Purchase of gas by a Releasing Shipper from a Replacement Shipper at the Releasing Shipper's Primary Delivery Point(s) shall not be deemed to be the exercise of a recall by the Releasing Shipper.

The Releasing Shipper shall provide capacity recall notification to Transporter via the LINK® System. The recall notification shall specify the recall notification period for the specified effective Gas Day, as well as any other information needed to uniquely identify the capacity being recalled.

Transporter shall support the following recall notification periods for all released capacity subject to recall rights:

Timely Recall Notification:

- A Releasing Shipper recalling capacity should provide notice of such recall to Transporter and the first Replacement Shipper no later than 8:00 A.M. CCT on the day that Timely Nominations are due;
- Transporter shall provide notification of such recall to all affected Replacement Shippers no later than 9:00 A.M. CCT on the day that Timely Nominations are due;

Early Evening Recall Notification:

- A Releasing Shipper recalling capacity should provide notice of such recall to Transporter and the first Replacement Shipper no later than 3:00 P.M. CCT on the day that Evening Nominations are due;

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- Transporter shall provide notification of such recall to all affected Replacement Shippers no later than 4:00 P.M. CCT on the day that Evening Nominations are due;

Evening Recall Notification:

- A Releasing Shipper recalling capacity should provide notice of such recall to Transporter and the first Replacement Shipper no later than 5:00 P.M. CCT on the day that Evening Nominations are due;
- Transporter shall provide notification of such recall to all affected Replacement Shippers no later than 6:00 P.M. CCT on the day that Evening Nominations are due;

Intraday 1 Recall Notification:

- A Releasing Shipper recalling capacity should provide notice of such recall to Transporter and the first Replacement Shipper no later than 7:00 A.M. CCT on the day that Intraday 1 Nominations are due;
- Transporter shall provide notification of such recall to all affected Replacement Shippers no later than 8:00 A.M. CCT on the day that Intraday 1 Nominations are due; and

Intraday 2 Recall Notification:

- A Releasing Shipper recalling capacity should provide notice of such recall to Transporter and the first Replacement Shipper no later than 2:30 P.M. CCT on the day that Intraday 2 Nominations are due;
- Transporter should provide notification of such recall to all affected Replacement Shippers no later than 3:30 P.M. CCT on the day that Intraday 2 Nominations are due.

For recall notification provided to Transporter prior to the recall notification deadline

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specified above and received between 7:00 A.M. CCT and 5:00 P.M. CCT, Transporter shall provide notification to all affected Replacement Shippers no later than one hour after receipt of such recall notification. For recall notification provided to Transporter after 5:00 P.M. CCT and prior to 7:00 A.M. CCT, Transporter shall provide notification to all affected Replacement Shippers no later than 8:00 A.M. CCT after receipt of such recall notification.

Transporter's notices of recalled capacity to all affected Replacement Shippers shall be provided via the LINK® System, along with written notice via e-mail communication to the individual the Replacement Shipper identified in the Replacement Shipper's bid submitted pursuant to Section 25.1(h) of these General Terms and Conditions. Such notices shall contain the information required to uniquely identify the capacity being recalled, and shall indicate whether penalties will apply for the Gas Day for which quantities are reduced due to a capacity recall. Upon receipt of notification of the recall from Transporter, each affected Replacement Shipper shall revise its nominations within the applicable nomination cycle in order to implement the recall. Each affected Replacement Shipper will be solely responsible for adjusting its supply and transportation arrangements, which may be necessary as a result of such recall. Replacement Shippers involved in re-release transactions may receive notice slightly after the first Replacement Shipper receives notice. The recalling Releasing Shipper may nominate the recalled capacity consistent with the applicable nomination cycle, pursuant to Section 4 of these General Terms and Conditions.

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If, on the day of a partial day recall, the quantity of gas delivered to the Replacement Shipper is in excess of the MDQ remaining on the replacement contract after the partial day recall and/or the quantity of gas delivered to the Releasing Shipper that recalled the capacity is in excess of the MDQ recalled by the Releasing Shipper, then the Shipper(s) to whom such excess gas is delivered will be charged the applicable Usage-2 Rate pursuant to Section 3.2(b) of Rate Schedule FTS on such excess quantites of gas in addition to all other applicable charges.

(2) Partial Day Recall Quantity.

The daily contractual entitlement that can be recalled by a Releasing Shipper for a partial day recall is a quantity equal to the lesser of:

(i) The quantity specified in the Releasing Shipper's notice to recall capacity; or
(ii) The difference between the quantity released by the Releasing Shipper and the Elapsed Prorata Capacity; or
(iii) The difference between the quantity released by the Releasing Shipper and the quantity actually delivered to the Replacement Shipper within the limitations of the MDQ.

In the recall notification provided to Transporter by the Releasing Shipper, the quantity to be recalled shall be expressed in terms of the adjusted total released capacity entitlements based upon the Elapsed Prorata Capacity. In the event of an intra-day capacity recall, Transporter shall determine the allocation of capacity between the Releasing Shipper and the Replacement Shipper(s) based upon the Elapsed Prorata Capacity only in the case of (ii) above.

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The amount of capacity allocated to the Replacement Shipper(s) shall equal the original released quantity less the recalled capacity. This allocated daily contractual quantity shall be used for purposes of nominations, billing, and if applicable, for overrun calculations. As a result of the allocation of capacity described in this section, Transporter shall not be obligated to deliver a combined quantity to the Releasing Shipper and the Replacement Shipper(s) that is in excess of the total daily contract quantity of the release.

(3) Reput Provisions.

Transporter shall support the function of reputting by the Releasing Shipper. The Releasing Shipper may reput previously recalled capacity to the Replacement Shipper pursuant to the reput rights and methods identified in the Releasing Shipper's notice to release capacity, as required by Section 25.1(g)(10) below. When capacity is recalled, such capacity may not be reput for the same Gas Day. The deadline for the Releasing Shipper to notify Transporter of a reput of capacity is 8:00 A.M. CCT to allow the Replacement Shipper to submit timely nominations for gas to flow on the next Gas Day.

(e) Bidding Period. Releasing Shipper may specify the date and time that the Bidding Period starts and the date that the Bidding Period ends, provided, however, that the Bidding Period shall not commence or end any later than the times set forth in Section 25.1(f) below. Releasing Shipper's offer shall be posted for the Bidding Period; provided, however, that the Releasing Shipper will have the right to withdraw its Releasing Shipper's Notice any time prior to the close of the Bid Period associated with such Releasing Shipper's Notice where unanticipated circumstances justify the withdrawal and no bids meeting the minimum conditions of Releasing Shipper's Notice have been made.

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Offers should be legally binding until written or electronic notice of withdrawal is received by Transporter. Transporter should post offers and bids, including prearranged deals, upon receipt. A releasing Shipper may request a later posting time for posting of such offer, and Transporter should support such request insofar as it comports with the standard Capacity Release timeline specified in Section 25.1(f) below.

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(f) The following capacity release timeline is applicable to all parties involved in the capacity release process; however, it is only applicable if (1) all information provided by the parties to the transaction is valid and (2) the Replacement Shipper has been determined to be creditworthy before the capacity release bid is tendered, and (3) there are no special terms or conditions of the release:

(1) For biddable releases (less than one (1) year):

- Offers should be tendered by 12:00 P.M. on a Business Day;
- Open season ends no later than 1:00 P.M. on a Business Day (evaluation period begins at 1:00 P.M. during which contingency is eliminated, determination of best bid is made, and ties are broken);
- Evaluation period ends and award posting if no match required at 2:00 P.M.;
- Match or award is communicated by 2:00 P.M.;
- Match response by 2:30 P.M.;
- Where match required, award posting by 3:00 P.M.; and
- Contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract. (Central Clock time)

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(2) For biddable releases (one (1) year or more):

- Offers should be tendered by 12:00 P.M. four Business Days before award;
- Open season ends no later than 1:00 P.M. on the Business Day before timely nominations are due (open season is three Business Days);
- Evaluation period begins at 1:00 P.M. during which contingency is eliminated, determination of Best Bid is made, and ties are broken;
- Evaluation period ends and award posting if no match required at 2:00 P.M.;
- Match or award is communicated by 2:00 P.M.;
- Match response by 2:30 P.M.;
- Where match required, award posting by 3:00 P.M.; and
- Contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract. (Central Clock Time)

(3) For non-biddable releases:

Timely Cycle:

- Posting of prearranged deals not subject to bid are due by 10:30 A.M.;
- Contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract. (Central Clock Time)

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Evening Cycle:

- Posting of prearranged deals not subject to bid are due by 5:00 P.M.;
- Contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract. (Central Clock Time)

Intraday 1 Cycle:

- Posting of prearranged deals not subject to bid are due by 9:00 A.M.;
- Contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract. (Central Clock Time)

Intraday 2 Cycle:

- Posting of prearranged deals not subject to bid are due by 4:00 P.M.;
- Contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract. (Central Clock Time)

(g) Required Information for the Release of Capacity. The Releasing Shipper shall submit the following information, objectively stated and applicable to all potential Shippers on a non-discriminatory basis, to Transporter via the LINK® System:

(1) The Releasing Shipper's legal name, contract number, and the name, title, address, e-mail address and phone and fax number of the individual who will authorize the release of capacity for the Releasing Shipper.

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(2) Whether the capacity is biddable.

(3) The level of daily firm entitlements that the Releasing Shipper elects to release, expressed as a numeric quantity per Day for transportation, which will be displayed in the LINK® System posting for prospective Replacement Shippers as the available MDQ.

(4) The Transportation Path(s) or segment within such Transportation Path(s), and quantity to be released.

(5) The requested effective date and the term of the release.

(6) The minimum acceptable period of release and minimum acceptable quantities (if any).

(7) The Releasing Shipper's maximum reservation rates (including any demand type surcharges, direct bills, or similar mechanisms), any minimum rate requirement, whether bids are to be submitted on a reservation or volumetric basis, and whether the bids should be stated in dollars and cents or percent of the maximum tariff rate. The maximum and minimum rates may separately identify surcharges and direct bills, or such amounts can be included in the total rate. For purposes of this Section 25, the maximum reservation rate(s) for Shipper paying a negotiated rate will be deemed to be the maximum rate(s) as set forth on the Statement of Rates for Transportation of Natural Gas.

(8) Whether the Releasing Shipper is requesting that Transporter actively market the capacity to be released.

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(9) The legal name of the Replacement Shipper that is designated in any pre-arranged release ("Prearranged Shipper").

(10) Whether the capacity is to be released on a recallable basis, and, if so, (i) the terms and conditions of such recall, including whether it is recallable on a full day or a partial day basis, (ii) whether the Releasing Shipper's recall notification must be provided exclusively on a Business Day, (iii) which recall notification period(s), as identified in Section 25.1(d) above, will be available for use by the parties, and (iv) any reput methods and rights associated with returning the previously recalled capacity to the Replacement Shipper.

(11) Whether the capacity to be released is contingent on the release of other capacity, or on certain terms and conditions, and if so, the capacity, terms and/or conditions upon which the release is contingent.

(12) The terms and conditions under which Releasing Shipper will accept contingent bids, including bids that are contingent upon the Replacement Shipper acquiring transportation on a pipeline interconnected to Transporter, the method for evaluating contingent bids, what level of proof is required by the contingent bidder to demonstrate that the contingency did not occur, and for what time period the next highest bidder will be obligated to acquire the capacity if the next winning contingent bidder declines the release.

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(13) Whether the Releasing Shipper will require the Replacement Shipper to post a deposit, not to exceed the amount required by Transporter pursuant to Section 25.2, to guard against payment defaults if Transporter waives the deposit requirement contained in Section 25.2. Such deposit will be paid by the Replacement Shipper to Transporter at the time specified in Section 25.2, and will be credited against the Replacement Shipper's invoices until fully utilized.

(14) The bid evaluation method which shall be, at the Releasing Shipper's option, either one of the following three standard evaluation methods: highest rate, net revenue or present value; or alternative Releasing Shipper defined bid evaluation methods pursuant to Section 25.1(g)(15) below; provided, however, that Transporter shall not be required to process the capacity release transaction using the standard process timeline should the Releasing Shipper elect an alternative method of bid evaluation.

(15) At the Releasing Shipper's option and in lieu of Transporter implementing the Best Bid determination stated in Section 25.1(k), the Releasing Shipper may state the bid evaluation method. Such bid evaluation method shall be objectively stated, applicable to all Replacement or Prearranged Shippers and not unduly discriminatory and shall enable Transporter to rank the bids received by utilizing the weight assigned by the Releasing Shipper to each element of the Releasing Shipper's Notice.

(16) Any restriction on the use of higher rate Secondary Delivery Points, or any requirement that the Replacement Shipper reimburse the Releasing Shipper for any incremental charges assessed by Transporter for use of Secondary Delivery Points by the Replacement Shipper.

(17) Any other additional information that Transporter deems necessary, from time to time, to effectuate releases hereunder.

Transporter shall not be liable for information provided by Shipper to Transporter, including any such information that is posted on the LINK® System.

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(h) Open Bidding Process. Prospective Shippers wishing to acquire capacity available for release ("Bidding Shipper"), shall place a bid on the LINK® System for the available capacity during the Posting Period. If such bid is not expressly labeled as a contingent bid, such bid shall be binding. The bid shall contain the following information:

(1) The Bidding Shipper's legal name and the name, title, address, phone number and e-mail address of the individual who will authorize the acquisition of the available capacity.

(2) The level of daily firm entitlements that the Bidding Shipper requests and the minimum quantity it will accept.

(3) The requested effective date and the term of the acquisition.

(4) The Bidding Shipper's bid, addressing all criteria required by the Releasing Shipper. The Bidding Shipper shall be entitled to withdraw its bid either via the LINK® System or EDM, prior to the end of the bidding period. Bidding Shipper cannot withdraw its bid after the Bidding Period ends. If Bidding Shipper withdraws its bid, it may not resubmit a lower bid. If Bidding Shipper submits a higher bid, lower bids previously submitted by Bidding Shipper will be automatically eliminated. A Bidding Shipper may have only one valid bid posted. Transporter shall post all information provided by Bidding Shippers, except the information provided in Section 25.1(h)(1), above.

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No bid shall exceed the maximum applicable Recourse Rates, in addition to any and all applicable fees and surcharges, as specified in this Tariff. The quantity or the requested term of the release of such bid shall not exceed the maximum quantity or primary term specified in the executed Agreement.

(i) Pre-Arranged Release. Releasing Shipper shall have the right to elect not to post a release for bidding if (1) the proposed capacity release has a duration of thirty-one (31) days or less and Releasing Shipper has obtained a Prearranged Shipper, or (2) for proposed capacity releases of any duration for which Releasing Shipper has obtained a Prearranged Shipper and the Prearranged Shipper is paying the maximum Recourse Rate and all other terms and conditions of the release are met. If Releasing Shipper exercises such right, Releasing Shipper must notify Transporter prior to the nomination of the released entitlements, and the Replacement Shipper shall adhere to the requirements set forth in Section 25.2. Releasing Shipper will post the information on the LINK® System by 9:00 a.m. the Day before the release transaction begins. The Replacement Shipper shall confirm the prearranged release by 9:30 a.m. and meet any eligibility requirements under this Section 25. Transporter will support the electronic upload of prearranged releases.

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(j) Matching Rights. A Prearranged Replacement Shipper shall have matching rights for a period of thirty (30) minutes following the time the Prearranged Shipper has been notified of the winning bid ("Matching Period"). In the event a higher bid is received, Transporter shall provide the Prearranged Shipper an opportunity during the Matching Period to match such higher bid. No later than 2:00 p.m. CT of the Day prior to the Day nominations are due, the Prearranged Shipper shall be notified via the LINK® System of the terms and conditions of the higher bid, and shall have the Matching Period to respond via the LINK® System. Absent a response from the Prearranged Shipper by 2:30 p.m. CT of the Day prior to the Day nominations are due, the capacity shall be awarded to the higher Bidding Shipper no later than 3:00 p.m. CT of the Day prior to the Day nominations are due.

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(k) Awarding of Capacity Available for Release. Capacity will be awarded no later than 3:00 p.m. CT of the Day prior to the Day nominations are due. The capacity available for release shall be awarded to the Bidding Shipper with the highest bid ("Best Bid") matching all terms and conditions provided by the Releasing Shipper. If multiple bids meet the minimum conditions stated in the Releasing Shipper's Notice, Transporter shall award the capacity, best bid first, until all offered capacity has been awarded. If bids are received that do not match all the terms and conditions provided by the Releasing Shipper, bids will be evaluated by the criteria provided by the Releasing Shipper. If no criteria are provided by the Releasing Shipper, the Bidding Shipper bidding the highest present value shall be awarded the capacity. Present value shall be determined based on a 10% discount rate. The ultimate awarding of capacity will be posted on the LINK® System by 3:00 p.m. CT on the Day prior to the Day nominations are due. Unless the bidder was a contingent bidder and the contingency did not occur, Transporter will tender an Addendum, as described in Article 1 of the Capacity Release Umbrella Agreement, to the winning bidder by 10:00 a.m. of the Day nominations are due.

Transporter shall not award capacity release offers to the Replacement Shipper until and unless the Replacement Shipper meets Transporter's creditworthiness requirements applicable to all services that it receives from Transporter, including the service represented by the capacity release.

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(l) Remaining Capacity. In the event that a Releasing Shipper does not release all of its firm entitlements, the Releasing Shipper shall remain responsible for the remaining entitlements and is entitled to utilize the remaining entitlements with the MDQ reduced accordingly by the released capacity quantities.

(m) No Rollover. The Releasing Shipper shall not release firm entitlements that were previously released pursuant to Section 25.1(i) to the same Prearranged Shipper on a prearranged basis, until twenty-eight (28) Days after the end of the first release period, unless the Prearranged Replacement Shipper agrees to pay the maximum rate and meet all other terms and conditions of the release.

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(n) Obligations of Replacement or Prearranged Shippers. The Replacement or Prearranged Shipper must satisfy all other provisions of this Tariff governing Shipper eligibility and must execute all required agreements and acknowledgements before it may contract with Transporter for the released capacity. In addition, as a pre-requisite to becoming a Replacement or Prearranged Shipper, a party must have been placed by Transporter on Transporter's pre-approved bidder list that is posted on the LINK® System. To be placed on such list, a party must have been accepted by Transporter as satisfying the credit standards of Section 27 of these General Terms and Conditions, must have executed a Capacity Release Umbrella Agreement and must continue to satisfy the credit standards of Section 27 when its bid is made and accepted or it is offered as a Prearranged Shipper, as applicable. Transporter shall process requests for credit approval with diligence. Any previously listed party that fails to continue to satisfy the standards of Section 27 shall be deleted from the list. Transporter will waive the credit requirements of Section 27 on a non-discriminatory basis for Replacement or Prearranged Shipper and permit such Replacement or Prearranged Shipper to submit bids, if the Releasing Shipper provides Transporter with a guarantee or other form of credit assurance in form and substance satisfactory to Transporter of all financial obligations of the Replacement or Prearranged Shipper with respect to the capacity being released by Releasing Shipper prior to the commencement of service to the Replacement or Prearranged Shipper if the release is pre-arranged and not subject to bidding or prior to the close of the bid period if the release is subject to bidding requirements of this Section 25. Any bid submitted will legally bind the Replacement or Prearranged Shipper to the terms of the bid if Transporter chooses such bid as the Best Bid until written or electronic notice of withdrawal is received by Transporter. Bids cannot be withdrawn after the bid period ends. Once the Replacement or Prearranged Shipper is awarded capacity, the Replacement or Prearranged Shipper becomes an existing Shipper like any other Shipper and is subject to the

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applicable provisions of Transporter's Tariff, including, but not limited to, Transporter's billing and payment and operational provisions. In addition, the Replacement or Prearranged Shipper as an existing Shipper may also release its capacity pursuant to this Section 25. Nominations may be submitted upon the award of capacity, and such nominations will be processed in accordance with the nomination and scheduling requirements of Sections 4 and 6 of these General Terms and Conditions; provided, however, in no circumstances will gas flow prior to the effective date of the release as specified in the Releasing Shipper's Notice.

(o) Capacity Release Umbrella Agreement. All nominations, scheduling and billing will be done under the contract number provided in the Addendum.

25.2 Obligations of the Parties.

(a) Contractual Obligations. All Replacement Shippers shall be required to comply with the provisions of Rate Schedule FTS and these General Terms and Conditions and to accept by a release all Transportation rights and obligations of the Releasing Shipper with respect to the capacity released, including, but not limited to, nominations and Transportation Paths. Furthermore, the Releasing Shipper shall remain fully liable to Transporter for all reservation rates, including reservation type surcharges and direct bills that were due under the Releasing Shipper's Agreement. In the event that the Replacement Shipper invoiced amounts for reservation rates are in arrears by 60 days or more, the Releasing Shipper shall be responsible for paying all such amounts with the next invoice rendered to the Releasing Shipper by Transporter.

(b) Billing. Pursuant to Sections 9 and 10, Replacement Shipper shall be billed for all reservation type charges contained within its bid and all usage charges according to Section 3 of Rate Schedule FTS.

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(c) Credits. Except as otherwise agreed to between Transporter and Releasing Shipper, Releasing Shipper shall receive a credit against its Monthly Reservation Charges equal to the amount of reservation rates contained within the Replacement Shipper's bid subject to the obligations of Releasing Shipper under Section 25.2(a).

(d) Refunds. Releasing Shipper and any Replacement Shipper must track any changes in Transporter's rates approved by the Commission. In the event the Commission orders refunds of any such rates charged by Transporter and previously approved, Transporter and/or Releasing Shipper, as the case may be, must make corresponding refunds to such Releasing Shipper or any Replacement Shipper, to the extent that Releasing Shipper or Replacement Shipper(s) has paid a rate in excess of Transporter's just and reasonable, applicable maximum rates. Transporter shall assume no liability or responsibility whatsoever for the failure of the Releasing Shipper to comply with its obligations under this Section 25.2(d).

25.3 Posting of Purchase Offers. Transporter shall allow a potential Replacement Shipper to post for at least thirty (30) Days its offers to acquire released firm entitlements. The offer must contain the following information:

(a) The potential Replacement Shipper's legal name and the name, title, address, phone number and e-mail address of the individual who will authorize the acquisition of the available capacity.

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(b) The daily quantities of capacity which the potential Replacement Shipper requests.

(c) The Receipt Points and/or Delivery Points where capacity is requested, as applicable.

(d) The requested effective date and the term of the acquisition.

25.4 Marketing Fee. Transporter shall be entitled, upon Releasing Shipper's request, to actively market the capacity available for release on Releasing Shipper's behalf. Transporter and Releasing Shipper will negotiate the terms and conditions upon which Transporter will market the Releasing Shipper's capacity.

25.5 Permanent Releases. A Shipper which has a currently effective executed Agreement with Transporter under Transporter's Rate Schedule FTS may release its capacity to a Replacement Shipper for the remaining primary term of the contract and be relieved of all liability under its Agreement prospectively from the effective date of such release, provided that the following conditions are satisfied:

(a) The Replacement Shipper executes a new Agreement under the applicable Rate Schedule;

(b) The Replacement Shipper agrees that the minimum bid acceptable to Transporter shall be a bid for the remainder of the term of Releasing Shipper's service agreement at the rate(s) Releasing Shipper is obligated to pay Transporter for the capacity to be permanently released and accepts all obligations of the Releasing Shipper;

(c) The Replacement Shipper meets all of the credit-worthiness requirements contained in Section 27 of the General Terms and Conditions of Transporter's Tariff.

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(d) Transporter may refuse to allow a permanent capacity release if it has a reasonable basis to conclude that it will not be financially indifferent to the release. If Shipper's request to permanently release capacity is denied by Transporter, Transporter shall notify Shipper via e-mail and shall include in the notification the reasons for such denial.

25.6 Transporter's Rights to suspend and/or Terminate Temporary Capacity Release Transactions.

(a) In the event of a temporary release for which: (i) the Releasing Shipper no longer maintains creditworthiness as outlined in Section 27 of Transporter's General Terms and Conditions and Transporter has terminated Releasing Shipper's Service Agreement; and(ii) the reservation charge specified in the applicable Addendum is less than the level of the reservation charge which the Releasing Shipper was obligated to pay Transporter (or, if the Releasing Shipper is paying a negotiated rate, the sum of all reservation-type and commodity-type charges), then Transporter shall be entitled to terminate the service described in the Addendum, upon 30 Days' written notice to the Replacement or Prearranged Shipper, unless the Replacement or Prearranged Shipper agrees, at its sole election, prior to the end of said 30-Day notice period to pay for the remainder of the term specified in the Addendum one of the following: (i) the reservation and commodity charges at levels which the Releasing Shipper was obligated to pay Transporter, (ii) the applicable maximum tariff rate, or (iii) such rate as mutually agreed to by Transporter and Replacement or Prearranged Shipper.

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(b) In the event of a temporary release for which the Replacement Shipper no longer satisfies Transporter's credit requirements as set forth in Section 27 of the General Terms and Conditions: (i) Transporter may notify the Releasing Shipper, without any liability or prior notice to Replacement Shipper, that the Replacement Shipper no longer meets the credit requirements of Transporter's Tariff; and (ii) subject to Transporter exercising its rights under Section 27 of the General Terms and Conditions to suspend and/or terminate such capacity release transaction, the firm capacity subject to the release transaction shall revert to Releasing Shipper immediately upon the effectiveness, and for the duration, of such suspension or permanently if the release transaction is terminated.

25.7 Notices to Releasing Shippers. Transporter shall provide the original Releasing Shipper with Internet E-mail notification reasonably proximate in time with any of the following formal notices given by Transporter to the Releasing Shipper's replacement Shipper(s), of the following:

(a) Notice to the Replacement Shipper regarding the Replacement Shipper's past due, deficiency, or default status pursuant to Transporter's tariff;
(b) Notice to the Replacement Shipper regarding the Replacement Shipper's suspension of service notice;
(c) Notice to the Replacement Shipper regarding the Replacement Shipper's contract termination notice due to default or credit-related issues; and
(d) Notice to the Replacement Shipper that the Replacement Shipper(s) is no longer creditworthy and has not provided credit alternative(s) pursuant to Transporter's tariff.

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26. REQUESTS FOR SERVICE

Specific requests for information concerning service(s) should be directed to:

Southeast Supply Header, LLC
Attention: Marketing Department
P.O. Box 1642
Houston, Texas 77251-1642
Telephone: 1-800-827-LINK, or in Houston (713) 989-LINK

Transporter shall provide the requested information orally, or in writing, as appropriate.

26.1 Requests for Service.

(a) Persons desiring a new service or an amendment to existing service under one of Transporter's Rate Schedules set forth in Volume No. 1 of Transporter's FERC Gas Tariff must be a LINK® System User pursuant to Section 24 of these General Terms and Conditions and must submit a request for service electronically via the LINK® System. Persons submitting a bid for firm service under one of Transporter's Open Access Rate Schedules pursuant to Section 27 of the General Terms and Conditions must submit the bid electronically via the LINK® System.

(b) A request for a new service or an amendment to an existing service shall contain the information identified on the Request for Service Information List posted on Transporter's public web site, as such list may be amended from time to time. Requests to amend existing service that will affect a Shipper's financial obligations to Transporter, without regard to the impact of any applicable discount or negotiated rates, are referred to as Billing Amendments. Requests to amend existing service that will not affect a Shipper's financial obligations to Transporter, without regard to the impact of any applicable discount or negotiated rates, are referred

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to as Non-Billing Amendments. A Shipper requesting a new service or an amendment to existing service shall also provide the following to Transporter:

(1) Either at the time of the request for new service or an amendment to existing service is submitted to Transporter or at the time of execution of the Service Agreement, such other information (if any), in writing, as may be required to comply with regulatory reporting or filing requirements; and

(2) Within ten (10) Business Days of the submittal of the request for new service or a request for a Billing Amendment, any credit information required to be provided pursuant to Section 27 of the General Terms and Conditions.

(c) Neither a request for new service nor a request that would result in a Billing Amendment shall be deemed to have been received by Transporter until Shipper has submitted such request online via the LINK® System and Transporter has received the information required or requested pursuant to this Section 26.1 and Section 26.3 of the General Terms and Conditions. A request that would result in a Non-Billing Amendment shall be deemed to have been received on the date such request is submitted in the LINK® System. If Transporter requests additional information or assurance in accordance with this Section 26.1, and such additional information or assurance is received within ten (10) Business Days of Transporter's request, Shipper's request for service shall be deemed to have been received on the date on which Shipper's additional financial information is received by Transporter; otherwise, Shipper's request for service shall be deemed to be null and void.

(d) If Shipper does not submit the information required in Section 26.1(b) above within the required timeframes,

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the request for service shall be considered to be null and void. In addition, Transporter shall reject any request for service created in the LINK® System by Shipper, but not submitted to Transporter within ninety (90) days of Shipper's creation of such request.

26.2 All firm transportation requests shall be subject to the following conditions:

(a) No request for transportation from a Primary Receipt Point or to a Primary Delivery Point shall be considered valid or be granted if to do so would impair Transporter's ability to render existing services pursuant to Transporter's firm service rate schedule(s).

(b) Subject to the provisions of (a) above, amendments to any firm Service Agreement or exhibit to add additional Primary Delivery Point(s) pursuant to an applicable firm rate schedule will not be considered a new transaction for purposes of complying with this Section 26. Any Shipper receiving permission from Transporter to use any new Primary Receipt Point(s) or new Primary Delivery Point(s) shall be deemed to have complied with the requirements of this Section 26 for purposes of receiving priority in contracting for such new Primary Receipt Point(s) or new Primary Delivery Point(s) for a firm Receipt Point MDQ or Delivery Point MDQ over any third party subsequently requesting firm transportation under a firm rate schedule at that Primary Receipt Point(s) or Primary Delivery Point(s) if, at the time of Shipper's request, said third party's request has not been accepted by Transporter. The priority for such new Primary Receipt Point(s) or Primary Delivery Point(s) shall be determined in accordance with this Section 26.

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(c) In certain situations, Transporter may use an accounting meter number to represent a physical location on its pipeline system. A Delivery Point identified on Shipper's executed Service Agreement(s) may be designated in the LINK® System by means of an accounting meter number and description that differs from the physical meter number and description specified on the Service Agreement. The same rights and obligations exist for both Transporter and Shipper regardless of whether a location is identified in Shipper's executed Service Agreement by means of a physical meter number or an accounting meter number.

26.3 Execution of Service Agreement and Amendments. A Service Agreement and/or an amendment to an existing Service Agreement shall be executed, as specified in this Section 26.3, by Shipper and Transporter following the completion of the approval process.

(a) All interruptible Service Agreements, all interruptible Service Agreement amendments, firm Service Agreements with a term of one (1) year or less, and all amendments for firm Service Agreements with a term of one (1) year or less shall be executed electronically via the LINK® System by Shipper and Transporter. All firm Service Agreements with a term of more than one (1) year and all amendments to firm Service Agreements with a term of more than one (1) year shall be executed in writing. A Service Agreement shall be executed and, if executed in writing returned to Transporter, within fifteen (15) days of the tender of a Service Agreement by Transporter. In the event Shipper fails to submit a valid nomination for transportation pursuant to an interruptible Service Agreement within ninety (90) days after the later of (i) the date service is to commence, (ii) the date the Service Agreement is fully executed by Shipper and Transporter, or (iii) the date that the facilities, if any, to be

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constructed are ready for service, the Service Agreement and the corresponding transportation request for service shall be considered null and void.

(b) For each of Transporter's firm Rate Schedule(s), the applicable Executable Contract Summary, in the form contained in this FERC Gas Tariff, reflects contract specific information that appears in the Form of Service Agreement associated with each of Transporter's firm Rate Schedule(s) and will serve as the executable version of the Service Agreement for Service Agreements with a term of one (1) year or less, when execution is performed electronically via the LINK® System. The Executable Contract Summary, the Form of Service Agreement, the Exhibit(s) executed by Shipper and Transporter, the applicable rate schedule, the General Terms and Conditions of this FERC Gas Tariff, and any applicable negotiated rate or discount agreement will comprise the entire agreement between Shipper and Transporter.

(c) For each of Transporter's interruptible Rate Schedule(s), the applicable Form of Service Agreement, in the form contained in this FERC Gas Tariff, will serve as the executable version of the Service Agreement. The Form of Service Agreement, the Exhibit(s) executed by Shipper and Transporter, the applicable rate schedule, the General Terms and Conditions of this FERC Gas Tariff, and any applicable negotiated rate or discount agreement will comprise the entire agreement between Shipper and Transporter.

26.4 Extension of Service Agreements. Prior to the expiration of the term of a Part 284 Service Agreement and prior to Transporter's posting the availability of capacity under Transporter's Right of First Refusal provisions, if applicable, Transporter and Shipper may mutually agree to an extension of the term of the Service Agreement (the exact length of which is to be negotiated on a case-by-case basis, in a not unduly discriminatory manner).

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26.5 It is a condition precedent to project financing that Transporter enter into firm service agreements for a minimum quantity of capacity with Shippers (or assignees or replacement Shippers) that meet the credit criteria in Section 27 below.

27. CREDITWORTHINESS

27.1 (a) Transporter shall not be required to (i) execute an Agreement providing for service under the applicable Rate Schedule for any Shipper who fails to meet Transporter's standards for creditworthiness, or (ii) initiate service for a Shipper who subsequently fails to meet Transporter's standards for creditworthiness, or (iii) continue service for any Shipper who is or has become insolvent or who, at Transporter's request, fails within a reasonable period to demonstrate creditworthiness pursuant to Transporter's standards.

(b) To permit Transporter to conduct a creditworthiness review, a Shipper shall, upon request by Transporter, render to Transporter: (i) complete and current financial statements, including annual reports, 10K reports or other filings with regulatory agencies, prepared in accordance with generally accepted accounting principles, or for non U.S.-based Shippers, prepared in accordance with equivalent principles; (ii) a list of corporate affiliates, parent companies and subsidiaries; and (iii) any credit reports available from credit reporting agencies. In addition to the establishment of creditworthiness: (i) Shipper must not be operating under any chapter of the bankruptcy laws and must not be subject to liquidation or debt reduction procedures under state laws such as an assignment for the benefit of creditors, or any informal creditors' committee agreement; (ii) Shipper should not be subject to the uncertainty of pending liquidation or regulatory proceedings which could cause a substantial deterioration in its financial condition, a condition of insolvency, or the inability of Shipper to exist as an ongoing business entity; (iii) if Shipper has an ongoing business relationship with Transporter, no undisputed delinquent balances should be consistently outstanding for any services performed previously by Transporter, and Shipper must have paid its account

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in the past according to the credit terms and contract provisions and not made deductions or withheld payment for claims not authorized by contract; and (iv) no significant collection, lawsuits or judgments are outstanding which would adversely impact the ability of Shipper to remain solvent.

(c) For purposes of Section 27.1(b) above, the insolvency of a Shipper shall be presumed by the filing by such Shipper or any parent entity thereof of a voluntary petition in bankruptcy or the entry of a decree or order by a court having proper jurisdiction adjudging the Shipper or any parent entity thereof bankrupt or insolvent. The insolvency of a Shipper shall also be presumed by the filing by the Shipper or its parent entity of a voluntary or involuntary proceeding, reorganization, receivership, liquidation, a debt reduction procedure, assignment for the benefit of creditors, formal or informal creditor restructuring agreement, or the filing of any case under the United States Bankruptcy Code, or any other applicable federal or state law.

(d) If any of the events or actions described in Section 27.1(c) above shall be initiated or imposed during the term of service hereunder, Shipper shall provide notification thereof to Transporter within two (2) Business Days of any such initiated or imposed event or action.

27.2 Credit Requirements for long-term Shippers (contracts greater than 1 year). Shipper shall at all times comply with one of the following creditworthiness requirements:

(a) Shipper (or an affiliate which guarantees Shipper's obligations under the Agreement) has an investment grade credit rating for its long term senior unsecured debt from Moody's Investor Service of Baa3 or better or from Standard & Poor's of BBB- or better. A Shipper who qualifies under this category initially but is later downgraded below such investment grade will be required to qualify pursuant to Section 27.2(b)below.

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(b) A Shipper whose long term senior unsecured debt does not have an acceptable rating as set forth in Section 27.2(a) above will be accepted as creditworthy if (i) Transporter determines that, notwithstanding the absence of an acceptable rating, the financial position of Shipper (or an affiliate who guarantees Shipper's obligations under the Agreement) is acceptable to Transporter and its lenders; or (ii) the Shipper provides an irrevocable letter of credit in an amount equal to twelve (12) months of estimated reservation charges under the Agreement; provided that such amount shall be adjusted annually to reflect any change in the estimated reservation charges under the Agreement for the succeeding twelve (12) months or (iii) Shipper provides other security acceptable to Transporter and its lenders, each acting reasonably.

Transporter shall provide such Shipper with a written statement supporting Transporter's request for the security amount requested at the time such security is requested. If Transporter rejects the security provided by Shipper in accordance with Section 27.2(b)(i)-(iii) above, Transporter shall re-issue its request for the security and include a written explanation for the rejection of the security previously provided by Transporter.

(c) Nothing herein shall be read to preclude Transporter from requiring, and enforcing for the term of the contracts, a greater amount of security in agreements supporting an application for a certificate to construct new or expanded facilities, including any replacement contract entered into upon a permanent release of capacity under such contract, any assignment of such contract or any resale of capacity subject to such contract in the event of a default.

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27.3 Credit Requirements for short-term Shippers (contracts less than 1 year). Shipper shall establish credit in accordance with Section 27.2.

(a) If a Shipper fails to establish creditworthiness as provided in Section 27.2, Shipper may still receive Transportation Service if, and only if, Shipper furnishes and maintains in effect one of the following at Shipper's discretion and acceptable to Transporter: (i) a written guarantee for unconditional payment from a third party which is creditworthy as determined above; or (ii) an irrevocable standby letter of credit; or (iii) a prepayment amount equal to the amount which would be charged to Shipper for six (6) month's service or the term of service, whichever is less, plus an amount equal to the three highest cashout payments, if any incurred during the previous twelve months, plus an amount equal to the cost of gas associated with any lending requirements requested under Rate Schedule PALS (if no prior history exists between the parties, Transporter shall determine the amount of advance payment hereunder to be deposited with Transporter) or (iv) other security acceptable to Transporter.

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(b) If a Shipper fails to maintain creditworthiness, as determined by Transporter in accordance with Sections 27.2 or 27.3(a), Shipper may continue to receive service for fifteen (15) days after written notice from Transporter of such failure, provided, however, that Shipper furnishes and maintains in effect one of the following at Shipper's discretion and acceptable to Transporter: (i) a written guarantee for unconditional payment from a third party which is creditworthy as determined above; or (ii) an irrevocable standby letter of credit; or (iii) an amount equal to the amount which would be charged to Shipper for six (6) month's service or the term of service, whichever is less, plus an amount equal to the three highest cashout payments, if any incurred during the previous twelve months, plus an amount equal to the cost of Gas associated with any lending requirements requested under Rate Schedule PALS; or (iv) other security acceptable to Transporter. If Shipper fails to provide Transporter with the appropriate credit under this Section 27.3(b) within such fifteen (15) day notice period, then Transporter may, without waiving any rights or remedies it may have, and subject to a 30 day notice to both the Commission and the Shipper, suspend further service until Shipper's compliance with 27.2(b) is obtained, provided, however, that if compliance is not made within the 30 day notice period, Transporter shall no longer be obligated to continue to provide service to such Shipper.

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(c) Transporter's credit appraisal procedures involve the establishment of dollar credit limits on a standardized nondiscriminatory basis which appraisal shall consider a number of relevant factors including but not limited to the cost of constructing any applicable facilities. To the extent that a Shipper's account(s) with Transporter do not exceed such limits and/or provided no new information regarding Shipper's financial or business position becomes known to Transporter, no new credit approval shall be necessary for Shipper's existing Agreement(s) unless subsequently amended; provided however, that Transporter shall have the right, with Shipper's assistance and cooperation, to update Shipper's credit file at any time.

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28. RIGHT OF FIRST REFUSAL

28.1 Purpose. The purpose of this Section 28 is to provide the necessary information pertaining to the right of long-term firm Shippers to continue firm Transportation Service at the expiration of their Agreements by exercising a right of first refusal.

28.2 Eligibility. Any Shipper with a firm Agreement under a Part 284 Rate Schedule with an initial term of greater than two (2) years must give notice to the Transporter that Shipper desires to continue its Agreement at least two years in advance of the end of the primary term of the Agreement, and any Shipper with a firm Agreement under a Part 284 Rate Schedule with a primary term of (i) at least twelve (12) months of consecutive Transportation Service, or (ii) firm Transportation Service Agreements with a primary term of more than one (1) year for service which is not available for twelve (12) consecutive months ("seasonal contracts") must give notice to Transporter that Shipper desires to continue its Agreement at least six (6) months in advance of the end of the primary term of the Agreement. Shipper also must agree that it will match (a) the longest term, up to the maximum term allowed by the Commission, and (b) the highest rate for such Service, up to the maximum Recourse Rate, that is offered by any other person desiring such capacity; provided, however, that Transporter shall not be obligated to provide service at less than the maximum Recourse Rate(s). A Shipper paying a negotiated rate which exceeds the maximum Recourse Rate will be considered for purposes of this Section 28.2 to be paying the maximum rate as set forth in the Statement of Rates for Transportation of Natural Gas. Failure of the Shipper to give the notice specified will constitute a waiver of the Shipper's right of first refusal.

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28.3 Procedure.

(a) Transporter shall notify Shipper no later than three (3) Months prior to the expiration of the Agreement whether any outstanding bona fide offers exist for Transporter's capacity at a higher rate and/or for a longer term which could be satisfied by the relinquishment of Shipper's capacity. Offers will be deemed bona fide if made in compliance with Section 26 of these General Terms and Conditions. Any party that has an outstanding request for firm service under Section 26 of these General Terms and Conditions shall be notified and given the opportunity to specify the rate and term it is willing to offer for Shipper's capacity. If Transporter has received any such offers, Transporter shall inform Shipper of the rate, up to the maximum rate, and the term, up to a maximum time allowable by the Commission, that has been offered for Shipper's capacity. Shipper shall notify Transporter within ten (10) Business Days after notification whether it desires to match the rate and term offered, and, if so, to provide a binding commitment in writing to Transporter to execute a contract containing said terms within the next thirty (30) Business Days.

(b) If Transporter does not notify Shipper of the existence of any offers for Shipper's capacity under Section 28.3(a), Transporter and Shipper may negotiate the terms and conditions of a new Agreement; provided, however, that in no event shall Shipper have any automatic right to renew service at a negotiated or discounted rate; provided further, however, Shipper may select the term of the Agreement after agreeing to pay maximum rates, and all applicable surcharges.

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29. INCORPORATION IN RATE SCHEDULES AND AGREEMENTS

These General Terms and Conditions are incorporated in and are a part of Transporter's Rate Schedules and Agreements. To the extent there is any inconsistency between terms in these General Terms and Conditions and terms in Transporter's Rate Schedules or Agreements, these General Terms and Conditions shall govern.

30. NEGOTIATED RATES

30.1 Availability. Notwithstanding anything to the contrary contained in this Tariff, Transporter and Shipper may mutually agree to a negotiated rate and contract term for all or any portion of the capacity under any Part 284 Agreement, provided that Shipper has not acquired its capacity under the capacity release provisions of Section 25. If only a portion of the capacity under any Agreement will be priced at negotiated rates, the original Agreement must first be bifurcated, and the existing maximum or discounted recourse rates will continue to apply to the Agreement not subject to the negotiated rates. If Transporter and Shipper fail to agree to a negotiated rate, Shipper may receive service at the applicable maximum tariff rates, including surcharges, for service under the Rate Schedule applicable to the service.

30.2 Filing Requirement. Transporter will submit to the Commission a tariff sheet stating the exact legal name of the Shipper, the negotiated rate, the rate schedule, the contract term, the Receipt Point(s), Delivery Point(s), the MDQ, and where applicable, the exact formula underlying a negotiated rate for any negotiated rate agreement. Unless Transporter executes and files a non-conforming Agreement, such tariff sheet will contain a statement that the negotiated rate agreement does not deviate in any material respect from the Form of Service Agreement for the applicable Rate Schedule.

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30.3 Limitations. This Section 30 does not authorize Transporter to negotiate terms and conditions of service.

30.4 Right of First Refusal. For purposes of exercising rights to continue service pursuant to Section 28 of these General Terms and Conditions, the highest rate that a Shipper must match if it desires to retain all or a portion of its capacity, and continue to receive firm service under the same rate schedule beyond the expiration date of such long-term firm Agreement, is the recourse rate for such service.

30.5 Accounting Treatment. Transporter shall maintain a separate account within Account 489.2, Revenues from transportation of gas of others through transmission facilities, for recording all revenues associated with charging negotiated rates. Transporter shall record each volume transported, billing determinant, rate component, surcharge, and the revenue associated with its Negotiated Rates so that this information can be filed, separately identified, and separately totaled, as part of and in the format of Statements G, I, and J in Transporter's next Section 4 rate case.

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31. NORTH AMERICAN ENERGY STANDARDS BOARD ("NAESB") STANDARDS

Transporter has adopted all of the Business Practices and Electronic Communication Standards that were required by the Commission in 18 CFR Section 284.12(b) in accordance with Order No. 587 et al. In addition to the standards reflected in other provisions of this Tariff, the following NAESB Wholesale Gas Quadrant ("WGQ") standards, definitions and data sets, Version 1.7, 2004 Annual Plan Item 2, 2005 Annual Plan Item 8 and in Recommendation R030350A, are incorporated herein by reference.

General Standards
0.3.1, 0.3.2, 0.3.3, 0.3.4, 0.3.5, 0.3.6, 0.3.7, 0.3.8, 0.3.9, and 0.3.10

Nominations Related Standards
1.2.1, 1.2.2, 1.2.3, 1.2.4, 1.2.5, 1.2.6, 1.2.8, 1.2.9, 1.2.10, 1.2.11, 1.2.13, 1.2.17, 1.2.18, 1.2.19, 1.3.2(vi), 1.3.3, 1.3.4, 1.3.14, 1.3.15, 1.3.16, 1.3.17, 1.3.18, 1.3.19, 1.3.20, 1.3.21, 1.3.22, 1.3.23, 1.3.24, 1.3.25, 1.3.26, 1.3.27, 1.3.28, 1.3.29, 1.3.30, 1.3.31, 1.3.32, 1.3.34, 1.3.35, 1.3.36, 1.3.37, 1.3.38, 1.3.39, 1.3.40, 1.3.41, 1.3.42, 1.3.43, 1.3.44, 1.3.45, 1.3.46, 1.3.47, 1.3.48, 1.3.49, 1.3.50, 1.3.51, 1.3.52, 1.3.53, 1.3.54, 1.3.55, 1.3.56, 1.3.57, 1.3.58, 1.3.59, 1.3.60, 1.3.61, 1.3.62, 1.3.63, 1.3.64, 1.3.65, 1.3.66, 1.3.67, 1.3.68, 1.3.69, 1.3.70, 1.3.71, 1.3.72, 1.3.73, 1.3.74, 1.3.75, 1.3.76, 1.3.77, 1.3.79, 1.4.1, 1.4.2, 1.4.3, 1.4.4, 1.4.5, 1.4.6, and 1.4.7

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GENERAL TERMS AND CONDITIONS
(CONTINUED)

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GENERAL TERMS AND CONDITIONS
(CONTINUED)

32. DEFAULT AND TERMINATION

32.1 Except where different procedures for termination of an Agreement are expressly provided in the General Terms and Conditions, if Transporter or Shipper shall fail to perform any of the covenants or obligations imposed upon it under any Agreement into which these General Terms and Conditions are incorporated, then in such event the other party may, at its option, terminate such Agreement by proceeding as follows: The party not in default shall cause a written notice to be served on the party in default stating specifically the default under the Agreement and declaring it to be the intention of the party giving the notice to terminate such Agreement; thereupon the party in default shall have 30 Days after the service of the aforesaid notice in which to remedy or remove the cause or causes stated in the default notice and if within the said 30 Day period the party in default does so remove and remedy said cause or causes and fully indemnifies the party not in default for any and all consequences of such default, then such default notice shall be withdrawn and the Agreement shall continue in full force and effect.

32.2 In the event the party in default does not so remedy and remove the cause or causes, or does not indemnify the party giving the default notice for any and all consequences of such default within the said period of 30 Days, then, after any necessary authorization by regulatory bodies having jurisdiction, at the option of the party giving such default notice, the Agreement shall terminate.

32.3 Any termination of the Agreement pursuant to the provisions of this Section 32 shall be without prejudice to the right of Transporter to collect any amounts then due to it for Gas delivered or service provided prior to the date of termination, and shall be without prejudice to the right of Shipper to receive any Gas which it has not received but the Transportation of which has been paid prior to the date of termination, and without waiver of any other remedy to which the party not in default may be entitled for breaches of the Agreement.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

33 STANDARDS OF CONDUCT COMPLIANCE PROCEDURES.

33.1 Complaints: In the event that a Shipper or potential Shipper has a complaint relative to service under this Tariff or Transporter's Standards of Conduct compliance procedures, the Shipper shall provide a description of the complaint, including the identification of the Transportation request (if applicable), to the appropriate contact personnel whose name(s) shall be posted on Transporter's Internet Website.

Transporter shall respond to a complaint within forty-eight (48) hours, and in writing within thirty (30) Days advising Shipper or potential Shipper of the disposition of the complaint. In the event the required date of Transporter's response falls on a Saturday, Sunday, or a holiday that affects Transporter, Transporter shall respond by the next Business Day.

33.2 Informational Postings

Transporter shall post on its Internet Website its procedures for implementation of and compliance with the Commission's Standards of Conduct regulations. All information required to be posted pursuant to such regulations, including, but not limited to, organizational charts, information on shared facilities and shared operating personnel, discounts granted, and notices of waivers and/or exercises of discretion in the application of tariff provisions, will be provided on Transporter's Internet Website under Informational Postings. Such information will be updated as required by applicable regulation(s) issued by the Commission.

Southeast

GENERAL TERMS AND CONDITIONS
(CONTINUED)

34. LIMITATION OF LIABILITY OF MEMBERS AND OPERATOR

Shipper acknowledges and agrees that (a) Transporter is a Delaware limited liability company; (b) Shipper shall have no recourse against any member of Transporter with respect to Transporter's obligations under any Agreement and its sole recourse shall be against the assets of Transporter, irrespective of any failure to comply with applicable law or any provision of any Agreement; (c) no claim shall be made against the company operating the business and physical operations of Transporter or its members or the officers, employees, and agents of operator or its members (collectively "Operator"), under or in connection with any Agreement and the performance by Operator of its duties as Operator (provided that this provision shall not bar claims resulting from the gross negligence or willful misconduct of the Operator) and Shipper shall provide the Operator with a waiver of subrogation of Shipper's insurance company for all such claims; and (e) this representation is made expressly for the benefit of the members in Transporter and the Operator.

GENERAL TERMS AND CONDITIONS
(CONTINUED)

35. DISCOUNT POLICY

35.1 Any Shipper desiring a discount of the maximum recourse rates for service under Transporter's open-access rate schedules must submit a valid request for such discount pursuant to the procedures of this Section 35. To be considered a valid request, Shipper must complete and submit a request for discount via the LINK® System, specifically including the information for all mandatory fields. Upon receipt of a valid request for a discount, Transporter will log such request and either deny or grant such request.

35.2 If and when Transporter discounts the rates applicable for service under any Service Agreement under Rate Schedules included in Transporter's FERC Gas Tariff, the amount of any such discount shall be accounted for as a reduction of maximum rates in the following sequence to the extent any of the following components are included in the maximum rate; the first item discounted shall be trackable rate components (if any), to the extent not otherwise agreed to in approved settlements, followed by the base rate (maximum less minimum rate and excluding all other components specified here).

35.3 In the event that Transporter agrees to discount its maximum recourse rates under any of its open-access rate schedules, Transporter and Shipper may agree to the types of discounts specified herein without such discounts constituting a material deviation from Transporter's pro forma service agreement. Transporter and Shipper may agree that a specified discounted rate will apply: (i) only to specified quantities under the Service Agreement; (ii) only if specified quantities are achieved or only with respect to quantities below a specified level; (iii) only during specified periods of the year or for a specifically defined period; (iv) only to specified points, combination of points, markets, transportation paths or other defined geographic area(s); (v) only to reserves committed by Shipper; (vi) only in a specified relationship to the quantities actually delivered (i.e., that the reservation charge will be adjusted in a specified relationship to quantities actually delivered);

GENERAL TERMS AND CONDITIONS
(CONTINUED)

(vii) so that the applicable rate may be adjusted in the following manner: when one rate component, which was equal to or within the applicable maximum and minimum recourse rates at the time Shipper received the Discount Confirmation pursuant to Section 35.5 below specifying the terms of the discount, subsequently exceeds the applicable maximum recourse rate or is below the applicable minimum recourse rate, so that such rate component must be adjusted downward or upward to equal the new applicable maximum or minimum recourse rate, then other rate components may be adjusted upward or downward to achieve the agreed-upon overall rate, so long as none of the resulting rate components exceed the maximum recourse rate or are below the minimum recourse rate applicable to the rate component (such changes to rate components shall be applied prospectively, commencing with the date a Commission order accepts revised tariff sheets; however, nothing contained herein shall be construed to alter a refund obligation under applicable law for any period during which rates which had been charged under a discount agreement exceeded rates which ultimately are found to be just and reasonable); and/or (viii) based upon published index prices for specific receipt and/or delivery points or other agreed-upon published pricing reference points for price determination (such discounted rate may be based upon a single published index price or the differential between published index prices or arrived at by formula; provided that the discounted rate shall not change the underlying rate design, shall not include any minimum bill or minimum take obligation, and shall define the rate component to be discounted). Notwithstanding the foregoing, no discounted rate shall be less than the applicable minimum rate.

35.4 In the event that Transporter rejects Shipper's request for a discounted rate, Transporter shall notify Shipper via e-mail of the reason for such rejection.

35.5 The terms of any discount request granted by Transporter pursuant to this Section 35 shall be transmitted by e-mail to Shipper in the form of a Discount Confirmation. The Discount Confirmation shall identify the applicable Shipper's name,

GENERAL TERMS AND CONDITIONS
(CONTINUED)

contract number, rate schedule, term of the discount, discount rate, applicable quantities, Receipt Point(s) and delivery, and/or the pipeline path being discounted. The Discount Confirmation may also include other information required for posting under the Commission's regulations and other conditions consistent with Section 35.3. No particular discount transaction shall be contractually binding on either Transporter or Shipper until Transporter has confirmed the terms of the discount upon Transporter's e-mail to Shipper of the Discount Confirmation for the transaction, subject to the underlying Service Agreement being fully executed. All discounts granted shall be effective no sooner than the beginning of the next gas day following the Gas Day on which the request is granted by Transporter. Once the discount is contractually binding, the Discount Confirmation will constitute an addendum to the underlying Service Agreement. Each such addendum is an integral part of the underlying Service Agreement as if executed by both parties and fully copied and set forth at length therein.

35.6 If Transporter's recourse rates are subject to refund at any time during the effectiveness of a Discount Confirmation, with respect to the applicable discounted rate, Shipper shall be entitled to refunds of payments made by Shipper only in the event that the final, non-appealable maximum recourse rate, whether usage-based or reservation-based, as determined by the Commission for a given time period is lower than the rate actually paid by Shipper during such time period. Subject to the condition precedent set forth in the immediately preceding sentence, Shipper's principal refund amount shall be equal to (i) with respect to usage-based rates, the product of (aa) the positive difference between the final, non-appealable maximum recourse rate and the discounted rate, and (bb) the quantities of gas delivered to Shipper, or for Shipper's account, during the refund period; and (ii) with respect to reservation-based rates, the product of (cc) the positive difference between the final, non-appealable maximum recourse rate and the discounted rate, (dd) the MDQ covered by the discounted rate, and (ee) the number of Months in the refund period (partial Months shall be prorated for the number of Days in the Month that fall within the refund period and a discounted rate that is not a Monthly rate shall be adjusted for purposes of this calculation to reflect the Monthly equivalent of the rate).

GENERAL TERMS AND CONDITIONS
(CONTINUED)

36. OFF-SYSTEM PIPELINE CAPACITY

From time to time, Transporter may enter into transportation and/or storage agreements with other interstate or intrastate pipeline companies (individually, an "off-system pipeline"). In the event that Transporter acquires capacity on an off-system pipeline, Transporter will use such capacity for operational reasons and will only render Transportation Service to Shippers on the acquired capacity pursuant to Transporter's Tariff and subject to Transporter's approved rates, as such tariff and rates may change from time to time. For purposes of Transportation Service on an off-system pipeline, the "shipper must have title" requirement is waived, permitting a Shipper utilizing such Service to have title to the Gas on such off-system pipeline.

FORM OF SERVICE AGREEMENT

INDEX

Southeast Supply Header, LLC
Executable Contract Summary for Service Agreement under
Form of Service Agreement in Original Volume No. 1

DATE (1):____________

CONTRACT NO.(1A) __________
RATE SCHED: FTS
MLL: ____________

PRIMARY TERM: Effective on (5A)__________ Ending on (5B)__________
and From (5C)__________ To (5D)__________ with Written Notice of (5E)__________

SERVICE REQUESTER NAME (2): ____________________
ADDRESS (6): ____________________
____
____

EXHIBIT C DATED (14): ____________ SUPERCEDES EXHIBIT C DATED (15): ____________

MDQ (3)	Effective From:	Effective To:

SUPERCEDING CONTRACT (7): ____________ SUPERCEDED BY: ____________

EXHIBIT A DATED (8): __________ SUPERCEDES EXHIBIT A DATED (9): ____________

FIRM POINTS OF RECEIPT (10):

Location:	RMDQ:	Effective From:	Effective To:	Maximum Receipt Pressure

EXHIBIT B DATED (11): ____________ SUPERCEDES EXHIBIT B DATED (12): ____________

SPECIFIC FIRM POINTS OF DELIVERY (13):

Location:	DMDQ:	Effective From:	Effective To:	Maximum Delivery Pressure

This Service Agreement, executed, pursuant to Transporter's effective tariff between Transporter and Service Requester is heretofore made a part of and subject to the aforementioned Form of Service.

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE FTS)

Date:(1)___________________________, Contract No.(1A)__________________

SERVICE AGREEMENT

This AGREEMENT is entered into by and between Southeast Supply Header, LLC,("Transporter") and (2)______________________________________ ("Shipper").

In consideration of the premises and of the mutual covenants herein contained, the parties do agree as follows:

1. Transporter agrees to provide and Shipper agrees to take and pay for service under this Agreement pursuant to Transporter's Rate Schedule FTS and the General Terms and Conditions of Transporter's Tariff, which are incorporated herein by reference and made a part hereof.

2. The Maximum Daily Quantity (MDQ) for service under this Agreement and any right to increase or decrease the MDQ during the term of this Agreement are listed on Exhibit C attached hereto. The Point(s) of Delivery are listed on Exhibit B attached hereto. Exhibit(s) A B and C are incorporated herein by reference and made a part hereof.

3. This Agreement shall be effective on (5A)___________ and shall continue until (5B)___________ ("Primary Term") and from (5C)______________ to (5D)______________ thereafter (not less than year to year for the secondary term for Agreements with a primary term of more than 1 year) until terminated by Transporter or Shipper upon at least (5E)_______[not less than 2 years for agreements with a primary term of 2 years or more and not less than 1 year for agreements with a primary term of more than 1 year but less than 2 years) prior written notice (if Transporter and Shipper agree on a fixed term, the evergreen and notice of termination language shall be deleted). Any portions of this Service Agreement necessary to correct or cash-out imbalances under this Service Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff shall survive the other parts of this Service Agreement until such time as such balancing has been accomplished.

   [Only with respect to an Agreement that was executed by Transporter and Shipper on or before December 29, 2006, add the following language:

   Notwithstanding any other provision in this Agreement, after service has commenced hereunder if as a result of an event of Force Majeure Transporter is not able to deliver Shipper's scheduled quantities for a period of one hundred eighty five (185) consecutive days during any three hundred sixty five (365) consecutive day period and at any minimum delivery pressure specified on Exhibit B of this Agreement, then Shipper shall have the right to terminate this Agreement or reduce the MDQ (with an associated reduction in the Delivery Point MDQs specified on Exhibit B of this Agreement) of this Agreement upon sixty (60) days prior written notice.]

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE FTS)

4. Maximum rates, charges, and fees shall be applicable to service pursuant to this Agreement except during the specified term of a discounted or negotiated rate to which Shipper and Transporter have agreed. Provisions governing such discounted rate shall be as specified in the Discount Confirmation to this Service Agreement. Provisions governing such negotiated rate and term shall be as specified on an appropriate rate sheet filed, with the consent of Shipper, as part of Transporter's Tariff. It is further agreed that Transporter may seek authorization from the Commission and/or other appropriate body at any time and from time to time to change any rates, charges or other provisions in the applicable Rate Schedule and General Terms and Conditions of Transporter's Tariff, and Transporter shall have the right to place such changes in effect in accordance with the Natural Gas Act. Nothing contained herein shall be construed to deny Shipper any rights it may have under the Natural Gas Act, including the right to participate fully in rate or other proceedings by intervention or otherwise to contest increased rates in whole or in part.

5. Unless otherwise required in the Tariff, all notices shall be in writing and mailed to the applicable address below or transmitted via facsimile. Shipper or Transporter may change the addresses or other information below by written notice to the other without the necessity of amending this Agreement:

Transporter:

Shipper:(6)

6. The interpretation and performance of this Agreement shall be in accordance with the laws of the State of _________, excluding conflicts of law principles that would require the application of the laws of a different jurisdiction.

7. This Agreement supersedes and cancels, as of the effective date of this Agreement, the contract(s) between the parties hereto as described below, if applicable,

(7) [None or an appropriate description]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers and/or Representatives thereunto duly authorized to be effective as of the date stated above.

SHIPPER:(2)____________________	SOUTHEAST SUPPLY HEADER, LLC
By:______________________________	By:______________________________
Title:__________________________	Title:__________________________

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE FTS)

EXHIBIT A

Point(s) of Receipt

Dated: (8)

To the service agreement under Rate Schedule FTS between Southeast Supply Header, LLC (Transporter) and (2)___________________________________ (Shipper) concerning Point(s) of Receipt.

The receipt points available to Shipper pursuant to Section 4.1 of Rate Schedule FTS includes the following, and any additional receipt points constructed after the effective date of this Agreement:

Receipt Point	Receipt Point MDQ	Maximum Receipt Pressure
(10)		

Signed for Identification

Transporter: ___________________________________

Shipper: _______________________________________

Supercedes Exhibit A Dated (9) __________________

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE FTS)

Exhibit B

Point(s) of Delivery

Dated: (11)

To the service agreement under Rate Schedule FTS between Southeast Supply Header, LLC (Transporter) and (2) ______________________________ (Shipper) concerning Point(s) of Delivery.

Primary Point of Delivery	Delivery Point MDQ	Minimum Delivery Pressure
(13)		

Signed for Identification

Transporter: ______________________________________

Shipper: ______________________________________

Supersedes Exhibit B Dated (12) ____________________

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE FTS)

Exhibit C

Transportation Quantities

Dated: (14)

To the service agreement under Rate Schedule FTS between Southeast Supply Header, LLC (Transporter) and (2) ________________________________ (Shipper) concerning transportation quantities.

MAXIMUM DAILY QUANTITY (MDQ): (3) _________ Dth

Dth	Period

Signed for Identification

Transporter: ____

Shipper: ____

Supersedes Exhibit C Dated (15) ________________________

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE PALS)

Date:__________________________, Contract No.__________________

SERVICE AGREEMENT

This AGREEMENT is entered into by and between Southeast Supply Header, LLC,("Transporter") and _____________________________________ ("Shipper").

In consideration of the premises and of the mutual covenants herein contained, the parties do agree as follows:

1. Transporter agrees to provide and Shipper agrees to take and pay for service under this Agreement pursuant to Transporter's Rate Schedule PALS and the General Terms and Conditions of Transporter's Tariff, which are incorporated herein by reference and made a part hereof.

2. The Maximum Park Quantity or Maximum Loan Quantity, as appropriate, and the PALS Point(s) of Transaction are set forth in the Exhibit(s) A to this agreement. Shipper shall initiate a request for each park or loan service transaction by executing and delivering to Transporter one or more Exhibit(s) A. Upon execution by Transporter, Shipper's Exhibit(s) A shall be incorporated in and made a part hereof.

3. This Agreement shall be effective on ___________ and shall continue until and including___________ ("Primary Term") and from ______________ to ______________ thereafter until terminated by Transporter or Shipper upon at least _______ prior written notice. Any portions of this Service Agreement necessary to correct or cash-out imbalances under this Service Agreement as required by Rate Schedule PALS and the General Terms and Conditions of Transporter's FERC Gas Tariff shall survive the other parts of this Service Agreement until such time as such balancing has been accomplished.

4. Maximum rates, charges, and fees shall be applicable to service pursuant to this Agreement except during the specified term of a discounted or negotiated rate to which Shipper and Transporter have agreed. Provisions governing such discounted rate shall be as specified in the Discount Confirmation to this Service Agreement. Provisions governing such negotiated rate and term shall be as specified on an appropriate rate sheet filed, with the consent of Shipper, as part of Transporter's Tariff. It is further agreed that Transporter may seek authorization from the Commission and/or other appropriate body at any time and from time to time to change any rates, charges or other provisions in the applicable Rate Schedule and General Terms and Conditions of Transporter's Tariff, and Transporter shall have the right to place such changes in effect in accordance with the Natural Gas Act. Nothing contained herein shall be construed to deny Shipper any rights it may have under the Natural Gas Act, including the right to participate fully in rate or other proceedings by intervention or otherwise to contest increased rates in whole or in part.

5. Unless otherwise required in the Tariff, all notices shall be in writing and mailed to the applicable address below or transmitted via facsimile. Shipper or Transporter may change the addresses or other information below by written notice to the other without the necessity of amending this Agreement:

   Transporter:

   Shipper:

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE PALS)

6. The interpretation and performance of this Agreement shall be in accordance with the laws of the State of _________, excluding conflicts of law principles that would require the application of the laws of a different jurisdiction.

7. This Agreement supersedes and cancels, as of the effective date of this Agreement, the contract(s) between the parties hereto as described below, if applicable:

   [None or an appropriate description]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers and/or Representatives thereunto duly authorized to be effective as of the date stated above.

SHIPPER:______________________

By:_____________________________

Title:__________________________

SOUTHEAST SUPPLY HEADER, LLC

By:___________________________

Title:________________________

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE PALS)

SOUTHEAST SUPPLY HEADER, LLC
PARK AND LOAN (PALS) AGREEMENT
DATED ____________

EXHIBIT A-__ DATED ____________

TRANSPORTER: Southeast Supply Header, LLC
5400 Westheimer Court
Houston, Texas 77056-5310

Attention: Duke Energy Gas Transmission Marketing Department

SHIPPER: ______________________
____
____
____

	Commencement Service Date		Termination of Service Date	Maximum Park/Loan Quantity	Specific Points
Park Service	________	________	________	________	
Loan Service	________	________	________	________	

SOUTHEAST SUPPLY HEADER, LLC

By______________________

ATTEST: ____________

[NAME OF SHIPPER]

By______________________

ATTEST: ____________

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS

This Umbrella Service Agreement, made and entered into this ____ day of _____________, by and between ______________________ (Replacement Shipper), and Southeast Supply Header, LLC (Transporter),

W I T N E S S E T H:

WHEREAS,

NOW, THEREFORE, for and in consideration of the mutual covenants and promises herein contained, the Replacement Shipper and Transporter hereby agree as follows:

ARTICLE I
SCOPE OF AGREEMENT

Subject to the terms, conditions and limitations hereof, so long as the financial evaluation and credit appraisal requirements are met in order for Replacement Shipper to be on Transporter's approved bidder list for capacity releases and execute this Umbrella Service Agreement pursuant to Section 25 of Transporter's GT&C, and this Umbrella Service Agreement is effective, Replacement Shipper may bid from time to time on proposed capacity releases under Rate Schedule FTS pursuant to the procedure set forth in Section 25 of Transporter's GT&C. If at anytime a bid submitted by Replacement Shipper is accepted by Transporter with respect to a given capacity release, Transporter will promptly finalize by means of Transporter's LINK® System the appropriate Addendum to this Umbrella Service Agreement, in the format attached hereto, depending upon the rate schedule under which the capacity is being released. An Addendum shall be deemed to be an executed Service Agreement under the rate schedule designated therein, subject to the terms and conditions of the rate schedule, the form of service agreement applicable to such rate schedule, and the General Terms and Conditions of Transporter's Tariff. The parties agree that each Addendum is an integral part of this Umbrella Service Agreement as if executed by the parties hereto and fully copied and set forth herein at length and is binding on the parties hereto. Upon finalization of such Addendum, Replacement Shipper and Transporter agree that Replacement Shipper shall be considered for all purposes as a Shipper with respect to the released service.

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(CONTINUED)

Upon the finalization of an Addendum, subject to the terms, conditions and limitations hereof and of Transporter's Rate Schedule FTS, Transporter agrees to provide the applicable released service for Replacement Shipper under the applicable rate schedule, provided however, the Replacement Shipper qualified under the financial evaluation and credit appraisal requirements set forth in Section 27 of Transporter's GT&C at the time it submitted the bid Transporter accepted with respect to such release.

Replacement Shipper hereby agrees to promptly provide any information necessary for Transporter to reevaluate Transporter's credit appraisal as contemplated by Section 27 of Transporter's GT&C and to advise Transporter of any material change in the information previously provided by the Replacement Shipper to Transporter.

ARTICLE II
TERM OF AGREEMENT

The term of this Agreement shall commence on _______________ and shall continue in force and effect until _________________ and _______________ to ____________________ thereafter unless this Umbrella Service Agreement is terminated as hereinafter provided. If Transporter determines at anytime that Replacement Shipper fails to meet the financial standards or credit criteria of Section 27 of the GT&C, Transporter may terminate this agreement and all Addenda attached hereto prospectively in accordance with Section 27 of the GT&C.

ARTICLE III
RATE SCHEDULE

This Umbrella Service Agreement does not have separate terms and conditions for particular services, but only provides a means for a Replacement Shipper to utilize a service subject to the applicable provisions of the relevant Service Agreement and the terms and conditions for Rate Schedule FTS, by finalization of a copy of an Addendum attached hereto and fully incorporated herein as a part of this Umbrella Service Agreement.

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(CONTINUED)

If Replacement Shipper utilizes an agent, it will so indicate on the appropriate Addendum, along with any terms and conditions relevant to such agency relationship. Transporter will act in accordance with the Addendum and in so acting will be fully protected in relying upon such agent.

Replacement Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to this Umbrella Service Agreement (b) the terms and conditions of this Umbrella Service Agreement, pursuant to which service hereunder is rendered or (c) any provision of the GT&C applicable to this Umbrella Service Agreement. Transporter agrees that the Replacement Shipper may protest or contest the aforementioned filings, unless the Replacement Shipper has otherwise agreed not to protest or contest any or all of the aforementioned filings, and the Replacement Shipper does not waive any rights it may have with respect to such filings.

ARTICLE IV
ADDRESSES

Except as herein otherwise provided or as provided in the GT&C of this Tariff, any notice, request, demand, statement, invoice or payment provided for in this Umbrella Service Agreement, or any notice which any party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered, certified, or regular mail to the post office address of the parties hereto, as the case may be, as follows:

(a) Transporter:

(b) Replacement Shipper:

or such other address as either party shall designate by formal written notice.

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(CONTINUED)

ARTICLE V
INTERPRETATION

The interpretation and performance of this Umbrella Service Agreement shall be in accordance with the laws of the State of __________, without recourse to the law governing conflict of laws.

This Umbrella Service Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter, either State or Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

ARTICLE VI
RELATIONSHIP BETWEEN REPLACEMENT SHIPPER
AND RELEASING SHIPPER

The parties recognize that, pursuant to Commission orders, Releasing Shipper may require that the Replacement Shipper agree that a breach of this Agreement, including a failure to pay, or to pay timely, by Replacement Shipper under this Agreement, constitutes a breach of contract as between Replacement Shipper and Releasing Shipper. The existence of such an agreement will be indicated on the appropriate Addendum to this Capacity Release Umbrella Agreement. If Replacement Shipper fails to pay Transporter, fails to timely pay Transporter, or otherwise breaches this Agreement with Transporter: (a) both Replacement Shipper and Releasing Shipper (except to the extent otherwise provided in Section 25.2(a) of the GT&C and except with respect to penalties attributable to Replacement Shipper's conduct) shall be liable to Transporter for such failure to pay or breach (it being understood that nothing in this Article VI relieves Releasing Shipper from responsibility to pay Transporter in accordance with its service agreements with Transporter) and (b) if, as a result of such breach by Replacement Shipper, Releasing Shipper is accordingly required to pay Transporter or otherwise perform, Releasing Shipper may have a cause of action for breach against Replacement Shipper.

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(CONTINUED)

IN WITNESS WHEREOF, the parties hereto have caused this Umbrella Service Agreement to be signed by their respective Presidents, Vice Presidents or other duly authorized agents and their respective corporate seals to be hereto affixed and attested by their respective Secretaries or Assistant Secretaries, the day and year first above written.

SOUTHEAST SUPPLY HEADER, LLC

By ___________________________________

ATTEST:

____

____

By ___________________________________

ATTEST:

____

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(continued)

Deal No.: __________
Southeast Supply Header, LLC Addendum Contract No.: __________
Capacity Release Umbrella Agreement No.:__________

Addendum No.____
Capacity Release Rate Schedule ___

Replacement Shipper: ____
Releasing Shipper: ____

Releasing Shipper's Contract No.: _____________

Begin Date of Release: _______________

End Date of Release: _______________

Rates: [Volumetric or Reservation]

U.S. $

Surcharges:

Description	Rate
____	$_______
____	$_______
____	$_______

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(continued)

Addendum No. ___ (Con't)
Capacity Release
Rate Schedule ___

Volume Commitment __________ (Dth/Monthly Billing Period)

Maximum Daily Quantity (MDQ): _______(Dth)

Billable Quantities:

Service:

From	To	Quantity

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(continued)

Addendum No.___ (Con't)
Capacity Release
Rate Schedule ___

Specific Firm Delivery Point(s):

Delivery Point	Delivery Point MDQ	Effective From	Effective To

Is this capacity subject to right of recall? Yes ____ No ____

Recall Conditions (if applicable):

____
____
____
____
____

Are there any restrictions on released capacity? Yes ____ No ____

Restrictions (if applicable):

____
____
____
____
____

FORM OF SERVICE AGREEMENT FOR
CAPACITY RELEASE UMBRELLA AGREEMENT UNDER
RATE SCHEDULE FTS
(continued)

Addendum No.___ (Con't)
Capacity Release
Rate Schedule ___

Was Southeasat Supply Header System, LLC's default bid evaluation criteria used?
Yes ___ No ___

Evaluation Criteria (if applicable):

____
____
____
____

Were contingent bids accepted? Yes ____ No ____

Contingency comments (if applicable):

____
____
____
____

Other Terms and Conditions of Release: [e.g., restrictions on release, third party agent and terms of third party agency relationship, and agreements between Replacement Shipper and Releasing Shipper]

FORM OF SERVICE AGREEMENT
FOR THE LINK® SYSTEM
(CONTINUED)

ARTICLE III
ADDRESSES

Except as provided in the General Terms and Conditions of Transporter's Tariff, any notice, request, demand, statement, bill or payment pursuant to this LINK® System Agreement shall be in writing and shall be considered as duly delivered when received on-line via the LINK® System, or when received as registered, certified, or regular mail at the address of the parties hereto, as the case may be, as follows:

(a) Transporter:

(b) LINK® System Subscriber:

or such other address as either party shall designate by completing and submitting the information required by the Contact Information Form, as such form is amended from time to time and posted on the LINK® System.

ARTICLE IV
INTERPRETATION

The interpretation and performance of this LINK® System Agreement shall be in accordance with the laws of the State of Texas without recourse to the law governing conflicts of law.

This LINK® System Agreement and the obligations of the parties are subject to all present and future valid laws with respect to the subject matter hereof, either State or Federal, and to all valid present and future orders, rules, and regulations of duly constituted authorities having jurisdiction.

FORM OF SERVICE AGREEMENT
FOR THE LINK® SYSTEM
(CONTINUED)

ARTICLE V
AGREEMENTS BEING SUPERSEDED

When this LINK® System Agreement becomes effective, it shall supersede any LINK® System Agreement(s) between the parties hereto with an earlier execution date.

IN WITNESS WHEREOF, the parties hereto have caused this LINK® System Agreement to be signed by their respective agents thereunto duly authorized, the day and year first above written.

SOUTHEAST SUPPLY HEADER, LLC

By:__________________________________

Title:_______________________________

____
Signature

LINK® System Subscriber

By:__________________________________

Title:_______________________________

____
Signature

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ITS)

Date:____________________________,

Contract No.___________________

SERVICE AGREEMENT

This AGREEMENT is entered into by and between Southeast Supply Header,LLC,("Transporter") and ______________________________________ ("Shipper").

In consideration of the premises and of the mutual covenants herein contained, the parties do agree as follows:

1. Transporter agrees to provide and Shipper agrees to take and pay for service under this Agreement pursuant to Transporter's Rate Schedule ITS and the General Terms and Conditions of Transporter's Tariff, which are incorporated herein by reference and made a part hereof.

2. Maximum Daily Quantity _____________ Dth

3. This Agreement shall be effective on ___________ and shall continue until ___________ ("Primary Term") and from ______________ to ______________ thereafter until terminated by Transporter or Shipper upon at least _______ prior written notice. Any portions of this Service Agreement necessary to correct or cash-out imbalances under this Service Agreement as required by the General Terms and Conditions of Transporter's Tariff shall survive the other parts of this Service Agreement until such time as such balancing has been accomplished.

4. Maximum rates, charges, and fees shall be applicable to service pursuant to this Agreement except during the specified term of a discounted or negotiated rate to which Shipper and Transporter have agreed. Provisions governing such discounted rate shall be as specified in the Discount Confirmation to this Service Agreement. Provisions governing such negotiated rate and term shall be as specified on an appropriate rate sheet filed, with the consent of Shipper, as part of Transporter's Tariff. It is further agreed that Transporter may seek authorization from the Commission and/or other appropriate body at any time and from time to time to change any rates, charges or other provisions in the applicable Rate Schedule and General Terms and Conditions of Transporter's Tariff, and Transporter shall have the right to place such changes in effect in accordance with the Natural Gas Act. Nothing contained herein shall be construed to deny Shipper any rights it may have under the Natural Gas Act, including the right to participate fully in rate or other proceedings by intervention or otherwise to contest increased rates in whole or in part.

5. Unless otherwise required in the Tariff, all notices shall be in writing and mailed to the applicable address below or transmitted via facsimile. Shipper or Transporter may change the addresses or other information below by written notice to the other without the necessity of amending this Agreement:

   Transporter:

   Shipper:

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ITS)

6. The interpretation and performance of this Agreement shall be in accordance with the laws of the State of _________, excluding conflicts of law principles that would require the application of the laws of a different jurisdiction.

7. This Agreement supersedes and cancels, as of the effective date of this Agreement, the contract(s) between the parties hereto as described below, if applicable:

   [None or an appropriate description]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers and/or Representatives thereunto duly authorized to be effective as of the date stated above.

SHIPPER:______________________

By:___________________________

Title:________________________

SOUTHEAST SUPPLY HEADER, LLC

By:___________________________

Title:________________________

REDACTED

West/East Pipeline Transportation Purchase Business Analysis Package

Sponsoring Business Unit: Regulated Fuels (RFD) of behalf of Progress Energy Florida

Funding Legal Entity: Progress Energy Florida (PEF)

Date Prepared: January 16, 2007

Contacts to discuss project

Dept/Group	Role/Name	Extension
Progress Fuels (RFD)	Bob Bazemore, VP and Project Sponsor	770-4083
Progress Fuels (RFD)	Kent Fonvielle, Manager	770-3257
Progress Fuels (RFD)	Rick Rhodes, Gas Supply Rep.	770-7613

CONFIDENTIAL EXHIBIT C
REDACTED VERSION

REDACTED

Exhibit ___
Estimated Total Annual Pipeline Costs
80% Utilization

Period[1]	Capacity (Dth/day)	Reservation Rate ($/Dth-day)	Fixed Costs	Total Variable	Total Costs
[redacted]					

(1) The projected in-service date of the Southeast Supply Header pipeline is June 1, 2008.
(2) Estimated variable costs based on 80% utilization of pipeline capacity.

CONFIDENTIAL EXHIBIT D

REDACTED

Exhibit ___
Estimated Total Annual Pipeline Costs
90% Utilization

Period(1)	Capacity (Dth/day)	Reservation Rate ($/Dth-day)	Fixed Costs	Total Variable	Total Costs
[redacted]	[redacted]	[redacted]			

(1) The projected in-service date of the Southeast Supply Header pipeline is June 1, 2008.
(2) Estimated variable costs based on 90% utilization of pipeline capacity.

CONFIDENTIAL EXHIBIT E

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southeast Supply Header, LLC	Docket Nos. CP07-45-000
Southeast Supply Header, LLC	Docket Nos. CP07-44-000
Southern Natural Gas Company	
Southeast Supply Header, LLC	Docket Nos. CP07-46-000
Southeast Supply Header, LLC	Docket Nos. CP07-47-000

NOTICE OF APPLICATION

(December 28, 2006)

Take notice that on December 18, 2006 Southeast Supply Header, LLC (SESH) filed an application in Docket No. CP07-45-000, requesting a certificate of public convenience and necessity pursuant to section 7 of the Natural Gas Act (NGA) and Subpart A of Part 157 of the Commission's regulations authorizing the Applicants to construct, own, operate, and maintain a new 269-mile natural gas pipeline system commencing in the area of the Perryville Hub near Delhi, Louisiana, continuing in a southeasterly direction through Mississippi and Alabama, and terminating near Coden, Alabama (SESH Project). In addition, SESH requests that the Commission issue to SESH: (i) a blanket certificate in Docket No. CP07-46-000 authorizing SESH to construct, operate, and abandon certain facilities under Part 157, Subpart F of the Commission's regulations; (ii) a blanket certificate in Docket No. CP07-47-000 authorizing SESH to transport natural gas, on an open access and self-implementing basis, under Part 284, Subpart G of the Commission's regulations; and (iii) authorizations necessary to charge initial recourse rates for certain services to be rendered by SESH.

Also take notice that on December 18, 2006, SESH and Southern Natural Gas Company (Southern Natural) filed with the Commission, in Docket No. CP07-44-000, for authorization under section 7 of the NGA and Part 157, Subpart A of the Commission's regulations to construct, own and operate certain jointly owned facilities which comprise a portion of the SESH Project (Joint Segment).

The application for SESH's and Southern Natural's proposals are more fully described as set forth in the applications that are on file with the Commission and open to public inspection. The instant filings may be also viewed on the web at http://www.ferc.gov using the "eLibrary" link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call (866) 208-3676 or TTY, (202) 502-8659

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Any initial questions regarding these applications should be directed to Brian D. O'Neill, LeBoeuf, Lamb, Greene & MacRae LLP. Telephone: (202) 986-8000.

On May 30, 2006, the Commission staff granted SESH's request to utilize the Pre-Filing process and assigned Docket No. PF06-28-000 to staff activities involving the SESH Project. Now, as of the filing of this application on December 18, 2006, the Pre-Filing Process for this project has ended. From this time forward, these proceedings will be conducted in Dockets No. CP07-44-000, CP07-45-000, CP07-46 -000, and CP07-47-000 as noted in the caption of this Notice.

Pursuant to Section 157.9 of the Commission's rules, 18 C.F.R. §157.9 and to ensure compliance with the Energy Policy Act of 2005, the Commission staff will issue a Notice of Schedule for Environmental Review within 90 days of the date of this Notice. The Notice of Schedule for Environmental Review will indicate, among other milestones, the anticipated date for the Commission staff's issuance of the final environmental impact statement (FEIS) for SESH's and Southern Natural's proposal. The Notice will also alert other agencies of the requirement to complete necessary reviews and authorizations within 90 days of the date of issuance of the Commission staff's FEIS.

There are two ways to become involved in the Commission's review of this project. First, any person wishing to obtain legal status by becoming a party to the proceedings for this project should, on or before the below listed comment date, file with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426, a motion to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the NGA (18 CFR 157.10). A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies of all documents filed by the applicant and by all other parties. A party must submit 14 copies of filings made with the Commission and must mail a copy to the applicant and to every other party in the proceeding. Only parties to the proceeding can ask for court review of Commission orders in the proceeding.

However, a person does not have to intervene in order to have comments considered. The second way to participate is by filing with the Secretary of the Commission, as soon as possible, an original and two copies of comments in support of or in opposition to this project. The Commission will consider these comments in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. The Commission's rules require that persons filing comments in opposition to the project provide copies of their protests only to the party or parties directly involved in the protest.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the

Commission. Environmental commenters will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. Environmental commenters will not be required to serve copies of filed documents on all other parties. However, the non-party commenters will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

Motions to intervene, protests and comments may be filed electronically via the internet in lieu of paper; see, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Comment Date: **January 18, 2007**

Magalie R. Salas
Secretary

Florida's Energy Plan

EXHIBIT
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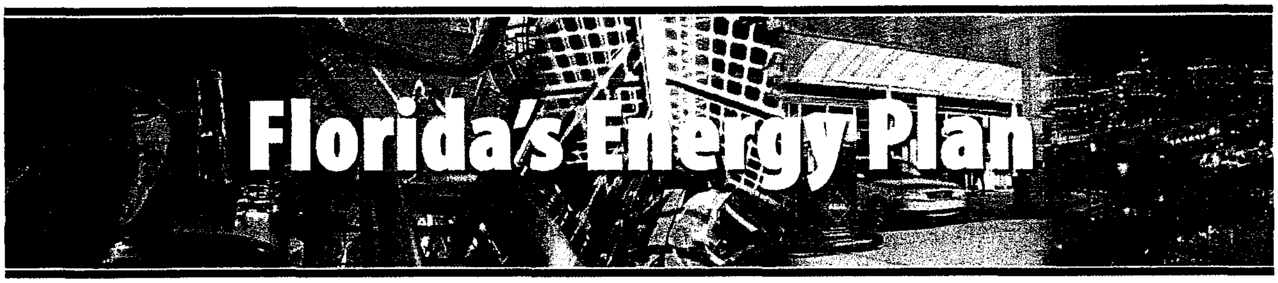
January 17, 2006

Department of Environmental Protection



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"An adequate, reliable, diverse, efficient and affordable energy supply, coupled with a long-term commitment to energy conservation, is vital for maintaining Florida's growing economy and quality of life."

- Colleen M. Castille

Secretary
Department of Environmental Protection

January 17, 2006

Governor Jeb Bush
The Capitol
402 South Monroe Street
Tallahassee, Florida 32399

Dear Governor Bush:

Since your issuance of Executive Order #05-241 on November 10, 2005, the Department of Environmental Protection has worked diligently to gather information toward a comprehensive energy plan for the State of Florida. As directed in your Order, the Department explored options for diversifying Florida's electric generation capacity, increasing and diversifying transportation fuel supply and increasing the State's conservation and efficiency initiatives.

Nationwide, demand for energy and transportation fuel is outpacing supply. At times over the last 18 months the margin of spare capacity in the oil market has fallen from the historic norms. In addition, the storms and hurricanes of 2004 and 2005 impacted lives and properties in a way we have never experienced before, severely disrupting petroleum and oil production and the nation's fuel supply systems. Production platforms in the Gulf of Mexico were shut down, pipelines were inoperable, and refining systems were off line for months – exposing our vulnerability and reliance on natural gas.

By evaluating Florida's current and future energy supply and demand, the Department has developed a suite of recommendations, built on the principals of conservation and efficiency, which provide the foundation for a far-reaching energy plan. In developing its proposals, the Department adopted two guiding principles: reliance on markets and no new taxes. Instead of mandates, recommendations rely on the power of the marketplace, using targeted incentives and government's purchasing power to stimulate the free market. Consumers have already been impacted with rising fuel costs – government should not add to that burden.

The Department is recommending that legislation be introduced during the 2006 Regular Legislative Session to increase capacity and diversify Florida's electric generation and transportation fuel supply by:

- Amending the Power Plant Siting Act and the Florida Electrical Transmission Line Siting Act to reduce regulatory barriers and streamline permitting.
- Amending Chapter 403.519, Florida Statues, to allow the Florida Public Service Commission to consider fuel diversity and fuel reliability as factors when determining the need for new electric generation.

- Increasing grant funding for research and demonstration projects associated with renewable energy systems and alternative fuel vehicles.

- Providing consumer and corporate rebates to encourage investments in solar technologies and ENERGY STAR™ appliances.

- Providing sales and corporate income tax incentives to encourage the production of clean fuels in Florida and for pollution-free hydrogen fuel cells, vehicles and fueling infrastructure.

- Establishing an energy council to provide policy advice and counsel to the Governor, Speaker of the House and President of the Senate.

Administratively, the Department will immediately begin working with other state agencies and entities to improve energy diversity, sustainability, efficiency and conservation statewide by:

- Adopting updated interconnection standards to include all distributed generation technologies, such as wind, solar and biomass.

- Requiring all new State government buildings to meet U.S. Green Building Council's Leadership in Environmental Design standards.

- Expediting State performance contracting with Energy Service Companies.

- Promoting awareness of energy conservation, alternative energy technologies and alternative fuel vehicles.

- Facilitating redundant and diverse petroleum supply and distribution mechanisms into and within Florida.

- Encouraging fueling stations to adopt a generator sharing program before the upcoming hurricane season as a cooperative method for allocating generators and reestablishing temporary power service after storm events.

- Fostering a state-level partnership with local planning boards to encourage well-designed transportation and transit systems within new community development.

An adequate, reliable, diverse, efficient and affordable energy supply, coupled with a long-term commitment to energy conservation, is vital for maintaining Florida's growing economy and quality of life. Florida must act now to respond to growing demand and to overcome the vulnerabilities highlighted by the hurricanes. We look forward to finalizing a comprehensive energy plan that will provide long-term energy security for the State of Florida.

Sincerely,

Colleen M Castille

Colleen M Castille
Secretary
Florida Department of Environmental Protection

STATE OF FLORIDA

OFFICE OF THE GOVERNOR

EXECUTIVE ORDER NUMBER 05-241

WHEREAS, according to a 2001 study by the United States Energy Information Administration, Florida ranks third in total energy consumption; and

WHEREAS, Florida's need for electrical generation is expected to grow by approximately 58 percent between 2002 and 2020; and

WHEREAS, Florida uses 8.6 billion gallons of gasoline per year, and consumption is growing by 300 million gallons per year; and

WHEREAS, less than one percent of Floridians own automobiles that use alternative fuels; and

WHEREAS, Florida has one of the nation's fastest growing populations with an average of 980 new residents arriving per day and approximately 80 million visitors arriving per year, thereby increasing the demand on Florida's energy supply; and

WHEREAS, current trends indicate Florida's dependence on natural gas to generate electricity will continue to increase; and

WHEREAS, Florida annually produces less than one percent of crude oil production and depends almost exclusively on other states and countries for supplies of oil; and

WHEREAS, catastrophic hurricane seasons in 2004 and 2005 have underscored Florida's vulnerability to disruptions in energy supply and the resulting impacts to Florida's economy, environment, and quality of life; and

WHEREAS, a long-term commitment to energy conservation in conjunction with an adequate, reliable, diverse, efficient, and affordable energy supply is vital to Florida's population growth, economic expansion and security; and

WHEREAS, the Governor's Office and the Governor's executive agencies are leading Florida's conservation efforts by adopting multi-phased, event based, cost-effective, efficient practices, which include, but are not limited to, replacing some traditional motor vehicles with hybrid vehicles, eliminating the use of non-essential equipment and appliances, turning off all lights, computers, and office equipment while not in use, and adjusting thermostats in state buildings;

NOW, THEREFORE, I, JEB BUSH, Governor of Florida, by virtue of the authority vested in me by the constitution and laws of the State of Florida, do hereby promulgate the following executive order:

Section 1. Energy Conservation.

The Governor's Office and the Governor's executive agencies are hereby directed to continue their energy conservation efforts to reduce the demand for energy in Florida and are further encouraged to develop innovative conservation initiatives to serve as a model for all Floridians. In addition, all other departments and agencies of state government, as well as all local governments, are hereby encouraged to develop and implement long-term conservation initiatives. For example, state and local governments should invest in energy efficient equipment and hybrid electric or alternative fuel vehicles.

Section 2. Energy Supply.

The State of Florida, through the Secretary of the Department of Environmental Protection shall develop a comprehensive energy plan by evaluating Florida's current and future energy supply and demand. This evaluation shall include an analysis of the following sectors: utility providers; petroleum companies; automobile manufacturers; fuel suppliers; technology companies; environmental organizations; researchers; the United States Department of Energy; members of the Florida Public Service Commission; members of the Florida Energy 2020 Study Commission; and consumers.

To assist with developing the State's energy plan, the Secretary of the Department of Environmental Protection shall host the 2005 Florida Energy Forum before December 31, 2005, in Tallahassee, Florida and serve as chairperson for the Forum. Forum participants shall address the diversification of Florida's energy supplies, energy generation, transmission, distribution, conservation and energy security, as well as discuss the barriers presented by government and potential incentives that may be offered to help Florida's future energy needs.

The State's energy plan shall consider all relevant topics, including, but not limited to the following:

A. Florida's current and projected energy needs.

B. A review of Florida's efforts to meet its current energy needs, including, but not limited to, laws, regulations, executive orders, Florida's Building Code, alternative energy investments through the Office of Tourism Trade and Economic Development, Florida's Energy 2020 Study Commission, Florida's Energy Future: Opportunities for Our Economy, Environment and Security Report, and conservation plans implemented by the state.

C. Florida's ability to generate, transmit and distribute electric power.

1. Florida's current and projected electric generating capacity for natural gas, liquefied natural gas, oil, coal, nuclear power, alternative and renewable energy sources (hydrogen, solar, biomass, wind and landfill methane), and other emerging energy technologies.

2. Florida's current and projected infrastructure needs for the production and supply of natural gas, liquefied natural gas, oil, coal, nuclear power, alternative and renewable energy sources (hydrogen, solar, biomass, wind and landfill methane), and other emerging energy technologies.

3. Florida's current and projected consumer costs of natural gas, liquefied natural gas, coal, nuclear power, alternative and renewable energy sources (hydrogen, solar, biomass, wind and landfill methane), and other emerging energy technologies.

4. Current regulatory oversight, both state and federal, of natural gas, liquefied natural gas, coal, nuclear power, alternative and renewable energy sources (hydrogen, solar, biomass, wind and

landfill methane), and other emerging energy technologies.

5. A review of Florida's successes in achieving energy efficiency.

6. Goals, both public and private, for the diversification of Florida's electric power supply.

D. Florida's ability to generate, store and distribute fuel.

1. Florida's current and projected capacity for gasoline, diesel fuel, ethanol, biodiesel, hydrogen and natural gas.

2. Florida's current and projected infrastructure needs for the production and supply of gasoline, diesel fuel, ethanol, biodiesel, hydrogen and natural gas.

3. Florida's current and projected consumer costs of gasoline, diesel fuel, ethanol, biodiesel, hydrogen and natural gas.

4. Current regulatory oversight, both state and federal, of gasoline, diesel fuel, ethanol, biodiesel, hydrogen and natural gas.

5. A review of Florida's successes in achieving energy efficiency.

6. Goals, both public and private, for the diversification of Florida's fuel supply.

E. Traditional and alternative fuel vehicles, consumer access to alternative fuels, the current and projected costs to consumers for traditional and alternative fuels, and the current and projected infrastructure needs for the production and supply of alternative fuel vehicles and the relative costs and benefits of any said alternatives.

F. Methods by which Florida can protect its energy supplies during an emergency.

G. Methods by which the State can reduce barriers and provide incentives to increase energy efficiency in power and fuel consumption.

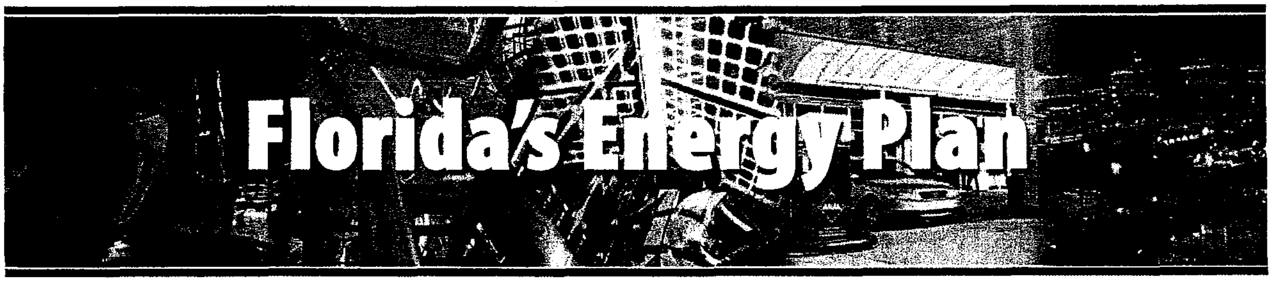
At the conclusion of the 2005 Florida Energy Forum, the Governor's Office and the Department of Environmental Protection will issue an updated energy strategy by no later than January 17, 2006.

H. All agencies under the control of the Governor are directed, and all other agencies are requested, to render assistance and cooperation to the 2005 Florida Energy Forum.

J. The Department of Environmental Protection shall provide all funds and administrative support necessary to implement the provisions of this Executive Order.

IN TESTIMONY WHEREOF, I have hereunto set my hand and have caused the Great Seal of the State of Florida to be affixed at Tallahassee, The Capitol, this 10th day of November, 2005.

Jeb Bush



I. Executive Summary

Florida's economy and quality of life depends on a secure, adequate and reliable supply of energy. As the fourth most populous state, Florida ranks third nationally in total energy consumption.

With more than 17 million citizens and nearly 1,000 new residents arriving daily, Florida is one of the fastest growing states in the nation. Because of its expanding economy, current forecasts indicate that Florida's electricity consumption will increase by close to 30 percent over the next ten years. But electricity demand presents just one challenge. Next to buildings, transportation is Florida's second largest energy use sector. The demand for motor vehicle transportation fuel currently tops 28 million gallons per day and is expected to increase to more than 32.3 million gallons per day during the next decade, assuming a 15 percent population increase.

Since the last review of Florida's energy policy in 2000, several unpredictable events have heightened concern over energy reliability, security and supply. The 2003 blackout in the northeast, along with tremendous back-to-back hurricane seasons in 2004 and 2005, demonstrated the impact power outages and fuel interruptions have on the nation's economic welfare.

Producing less than one percent of the energy it consumes and limited by its geography, Florida is more susceptible to interruptions in energy supply than any other state. Unlike other states that rely on petroleum pipelines for fuel delivery, more than 98 percent of Florida's transportation fuel arrives by sea. The state's reliance on imported petroleum products, in addition to its anticipated growth in consumption, underscores its vulnerability to fluctuations in the market and interruptions in fuel production, supply and delivery.

The need to pursue a comprehensive energy plan for Florida cannot be understated. Energy demand is increasing at a significant rate. In turn, such increases have the potential to contribute to a continued limited market and sustained higher oil and natural gas prices.

Energy Production and a Growing Economy

Florida depends almost exclusively on other states and nations for supplies of oil and gasoline, generating less than one percent of the nation's crude oil production annually.

To generate electricity, Florida primarily relies on natural gas, coal and oil imports.

Together, fossil fuels represent 86 percent of Florida's total generating capacity. Less than 10 percent of its generating capacity is derived from cleaner nuclear and renewable fuels. In fact, no new nuclear plants have entered service in Florida since 1983.

Current forecasts indicate that new generation capacity will be 80 percent natural gas-fired and 19 percent coal-fired. Meeting these projections could prove expensive at today's prices and lead to an over-reliance on one fuel type, affecting the reliability of electric utility generation supply in Florida. While expansions for natural gas capacity are needed and already underway, improving generation fuel diversity would enhance reliability over the long-term. Too great a reliance on a single fuel source leaves Floridians subject to the risks of price volatility and supply interruption.

A New Class of Energy

Although the nation's reliance on traditional fossil fuels is currently high, Florida is investing in alternative fuels and developing "next generation" energy technologies. In 2003, Governor Jeb Bush launched "H2 Florida" to accelerate the commercialization of hydrogen technologies and spur economic investment in Florida's economy. With a four to one return on investment, Florida and its federal partners have invested $9 million to date in hydrogen infrastructure. Construction of a "hydrogen highway" is underway, 28 hydrogen demonstration projects are in progress and more than 100 hydrogen research and development projects are taking place at Florida's universities.

Utilization of biofuels is in its infancy with the cost of renewable fuels relatively high compared with traditional hydrocarbon fuels. Currently, Florida has just one biodiesel facility and, absent a manufacturing plant, imports ethanol from refineries outside of the state. Increasing production, supply and infrastructure of biofuels through financial incentives would provide both economic and environmental returns for the state. Likewise, a stronger investment both residentially and commercially in solar technology would not only reduce utility costs but generate pollution-free power for Floridians. To date, solar technology has remained largely inefficient and expensive, however, costs are gradually decreasing as system quality and reliability increases. To encourage continued investment in solar energy, systems received a permanent exemption from Florida sales and use tax in 2005.

Storm Impacts and Hurricane Recovery

The unprecedented level of storm activity during the 2004 and 2005 hurricane seasons spotlighted Florida's vulnerability to energy supply disruptions both in terms of power generation and transportation fuel supply. The impacts of the 2005 summer storms were particularly widespread. During the peak of the hurricane season, Panhandle ports remained closed to ocean traffic for several days, leaving residents and businesses without fuel. As Hurricane Rita followed Hurricane Katrina through the Gulf of Mexico, the Florida Reliability Coordinating Council declared a generating Capacity Advisory, appealing for conservation to prevent potential brownouts. Across the nation, production shortages led to a jump in natural gas prices and an increase in oil prices; gasoline prices rose to more than $3 per gallon and winter heating expenses were expected to increase by up to 35 percent over the previous year.

The Gulf of Mexico is of critical importance to the nation, supplying 29 percent of the nation's domestic oil production and 19 percent of the domestic gas production. When Hurricane Katrina hit on August 30, 2005, 95 percent of daily oil production and 88 percent of daily gas production was shut down. The storm left offshore production facilities, coastal refineries, pipelines and other energy infrastructure severely damaged. By January 2006, nearly five months after the storm, more than a quarter of the oil production and 19 percent of natural gas production from federal leases in the Gulf of Mexico remained shut down. Approximately 100 oil and gas platforms in federal waters remain out of service today. The United States Mineral Management Service estimates that cumulative production losses from Hurricanes Katrina and Rita so far amount to 547 million barrels of oil, equivalent to more than 20 percent of yearly oil production in the Gulf of Mexico. Full recovery of oil and natural gas production along the Gulf Coast is not expected until the summer of 2006, keeping pressure on energy prices.

A Vision for Florida's Future

Florida's energy policy was last reviewed by the Florida Energy 2020 Study Commission in 2000. The Commission addressed extended forecasts of energy supply and demand, reliability of the electric and natural gas supply within the state, emerging electric generation technologies, the potential impact of electrical restructuring and deregulation, and the environmental impact of electricity supply production, generation, and transmission in the state. Since then, considerable advances have been made in "next generation" energy technologies. In addition, Florida's experiences during the past two hurricane seasons have highlighted the critical need to reduce the state's susceptibility to energy disruptions.

To begin laying the foundation for Florida's energy future, Governor Bush signed Executive Order #05-241 on November 10, 2005, directing State government, through the Secretary of the Department of Environmental Protection (DEP), to develop recommendations for a new comprehensive statewide energy plan. The Order also directed State executive agencies to continue their energy conservation efforts and encouraged the development of additional innovative conservation initiatives to serve as a model for all Floridians.

To assist with developing new energy policy, the Order directed the DEP to convene a public energy forum. On December 14, 2005, DEP Secretary Colleen Castille hosted the 2005 Florida Energy Forum in Tallahassee, inviting representatives from Florida's Public Service Commission, the U.S. Department of Energy, utilities, fuel companies, alternative and renewable energy experts, businesses, the Florida Legislature and the environmental community to provide input and guidance on achieving energy security.

Forum participants examined a breadth of issues included in the charge from the Order, addressing the diversification of Florida's energy supplies, energy generation, transmission, distribution, conservation and efficiency, along with existing regulatory barriers and potential incentives for achieving energy security.

As a result, this report contains recommendations for achieving a diverse and reliable energy future that is built on the underlying principles of conservation and efficiency:

- The state's energy should be derived from a wide mix of available fuel sources and technologies, incorporating home-grown energy from renewable resources and alternative fuels and avoiding reliance on any one fuel type.

- The state's energy supply should be reliable, with redundancy in fuel delivery mechanisms and expanded capacity.

- Government, businesses and consumers should maximize the use of energy consumed, employing sustainable practices, eliminating waste and adopting conservation measures.

- Government, businesses and consumers should utilize energy efficient products and practices that use less energy, conserve resources and reduce utility costs.

- Florida should support its energy strategy by leveraging the incentives provided in the 2005 Federal Energy Policy Act

To prevent duplication where other official entities are acting, this report touches briefly on improving electric infrastructure. Following damage to electric transmission service lines and subsequent extended power outages during the 2005 hurricane season, the Public Service Commission is hosting an Electric Infrastructure workshop with electric utilities, cooperatives and local governments on January 23, 2006 to focus on actions needed for minimizing future infrastructure damage.

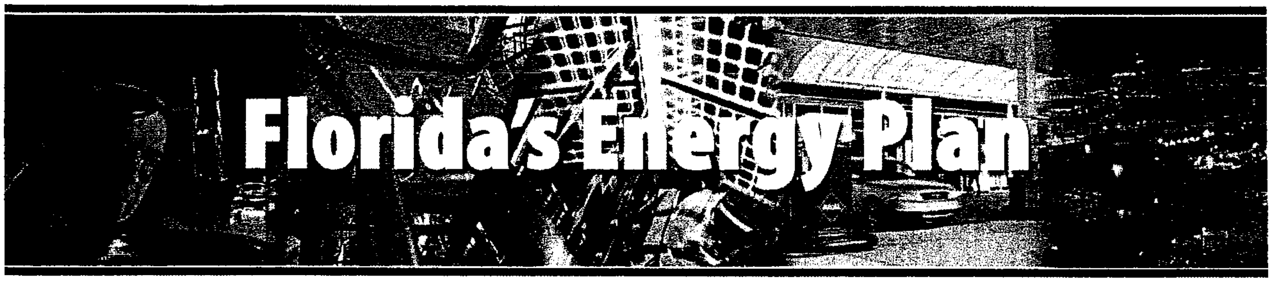
The recommendations outlined in this report describe administrative actions for immediate implementation, proposals for legislative action during the 2006 Regular Legislative Session and policy improvements that will enhance electric power generation and transportation fuel supply to help provide energy stability over the long-term.

Recommendations for Electricity Generation

- Streamline and expedite the siting and permitting of generation resources by revising the provisions of the Florida Electrical Power Plant Siting Act.
- Streamline and expedite the siting and permitting of electric transmission and distribution resources by revising the provisions of the Florida Electrical Transmission Line Siting Act. Incorporate the siting of substations into the Transmission Line Siting Act.
- Promote fuel diversity, fuel supply reliability and energy security.
- Facilitate additional fuel delivery mechanisms in Florida for power generation. Expedite all State permits required for the redundancies and increased capacity.
- Adopt updated interconnection standards to include all distributed generation technologies.
- Establish an energy council to provide policy advice and counsel to the Governor, Speaker of the House and Senate President.
- Expedite State performance contracting with Energy Service Companies.
- Promote awareness of energy conservation and alternative energy technologies.
- Use discretionary enforcement authority to allow approved alternative energy projects that provide a greater public benefit in lieu of civil monetary penalties.
- Require all new State government building construction to meet the U.S. Green Building Council's Leadership in Environmental Design standards. Encourage local governments and community developers to adopt high performance green building practices.
- Provide grant funding for research and demonstration projects associated with the development and implementation of renewable energy systems. Expand solar, hydrogen, biomass, wind, ocean current and other emerging technologies.
- Identify alternative energy production and distribution industries as Qualified Target Industries.
- Provide consumer and commercial rebates to assist with initial cost of photovoltaic and solar thermal technology installations on residential and commercial buildings.
- Provide consumer rebates for purchases of energy efficient ENERGY STAR™ appliances.
- Provide sales and corporate tax incentives for the manufacture, purchase and use of fuel cells for supplemental and backup power.

Recommendations for Transportation Fuels

- Facilitate additional and diverse petroleum supply and distribution mechanisms into and within Florida. Expedite all State permits required for the redundancies and increased capacity.
- Encourage fueling stations to cooperatively adopt a system modeled after the Florida WARN System to facilitate the relocation and use of generators to reestablish service.
- Foster state-local partnerships to encourage well-designed transportation and transit systems between established communities and within new community development.
- Raise public awareness for alternative fuel vehicles through public programs. Encourage public entities, including school districts and local governments, to use biofuels in fleets.
- Provide grant funding for applied research and demonstration projects associated with the development and implementation of alternative fuel vehicles and other emerging technologies.
- Provide sales and corporate income tax credits for hydrogen vehicles and fueling infrastructure.
- Provide corporate sales and income tax incentives to improve production, develop distribution infrastructure and increase availability of clean fuels, including biodiesel and ethanol.



II. Florida's Ability to Generate, Transmit and Distribute Electric Power

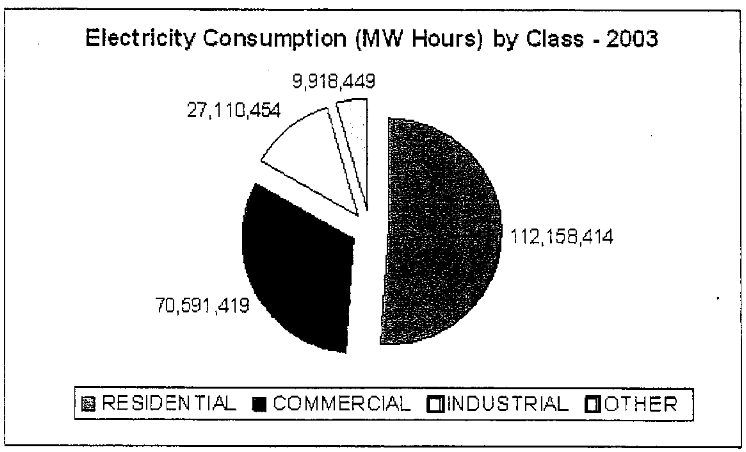
A. Current and Projected Electric Generating Supply and Demand

According to a 2001 study by the United States Energy Information Administration, Florida ranks third nationally in total energy consumption. Florida's demand for electric generation is expected to grow by approximately 58 percent between 2002 and 2020.

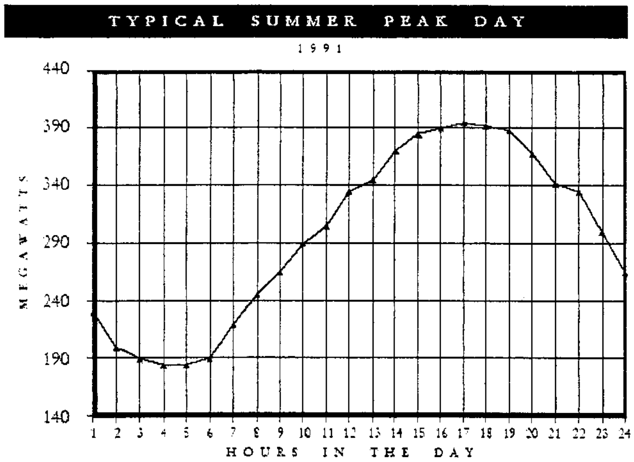
Florida currently has 57 electric utilities, consisting of five investor-owned (IOU), 18 cooperatively owned, and 34 municipally owned utilities. The largest investor owned utilities include Florida Power & Light Company (FPL), Progress Energy Florida, Tampa Electric Company (TECO), and Gulf Power Company (Gulf). The largest cooperatively owned utility is Seminole Electric Cooperative, and the largest municipally owned utilities are Jacksonville Electric Authority, Orlando Utilities Commission, City of Tallahassee, City of Lakeland, and Gainesville Regional Utilities.

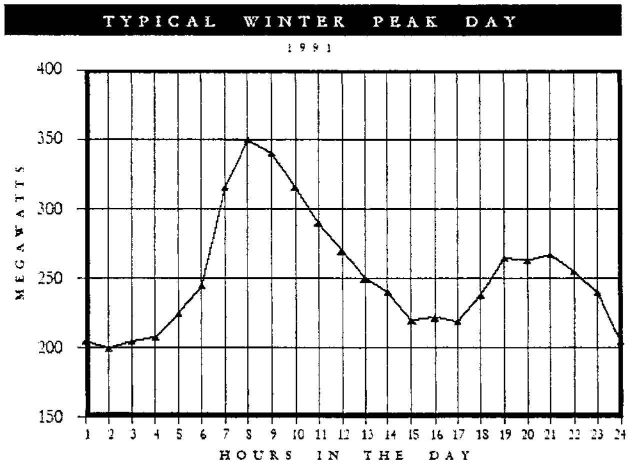
Based on 2003 data, 51 percent of all electric energy was consumed by residential customers, 32 percent by commercial customers, and 12 percent by industrial customers, with approximately two percent being used for other purposes. The following graphic displays the actual megawatt hours consumed by each customer class in 2003.

As illustrated above, the load profile of Florida is heavily influenced by the residential customer class. Due to high residential consumption, Florida must have adequate energy generation capacity to satisfy the changing needs of consumers throughout the day.



A representation of the typical summer and winter peak load profiles is shown below. [1]





It is Florida's fast growing population combined with the unique operational constraints of satisfying these peak summer and winter load profiles which dictates the need for continued growth in electric generation capacity.

Currently, Florida's electric utilities have 51,377 megawatts[2] (winter ratings[3]) of installed capacity[4] to meet the needs of customers. To meet Florida's growing demand for electricity, an acceleration of power plant construction is occurring. Over the next ten years, Florida's electric utility industry is constructing or planning to add approximately 19,390 megawatts (winter ratings) of new generating capacity. Future electric needs will also continue to be supplemented by utility demand-side management, energy efficiency programs and electricity production from renewable resources. Electricity consumption statewide, currently at 241,514 gigawatt-hours[5], is also expected to significantly increase during the ten-year planning horizon. Current forecasts indicate that electricity consumption will increase more than 67,276 gigawatt-hours (27.9 percent) over the next ten years.

To meet the changing load on Florida's electric systems, utilities must construct and operate various types of units. Baseload generation, primarily made up of large coal-fired and nuclear units, meets the load that is continuously on the system. These units have high capital costs but lower fuel costs associated with their operation. As the load rises during the day, intermediate units, primarily oil and natural gas-fired, are brought on line and then ramped down as the load decreases at night. These units may run for between 50 and 70 percent of the day and generally have lower capital costs to construct, but higher fuel costs. To meet peak demand combustion turbine units, primarily oil and natural gas-fired, are cycled on for shorter periods. These units may only run between five and 20 percent of the day depending upon weather conditions. Combustion turbine units generally

1 Florida Energy 2020 Study Commission Report, 2001

2 A megawatt (MW = 1,000 kilowatts) is a measure of real power at any instant in time, that is, a measure of demand on the grid at any moment in time. A typical home might have a demand that ranges from 1 to 10 kilowatts or more depending on what electrical appliances were being used.

3 Electric generating facilities have different megawatt ratings for the summer and winter seasons as cooler temperatures typically allow for higher output.

4 Includes existing generation and purchases from outside the state.

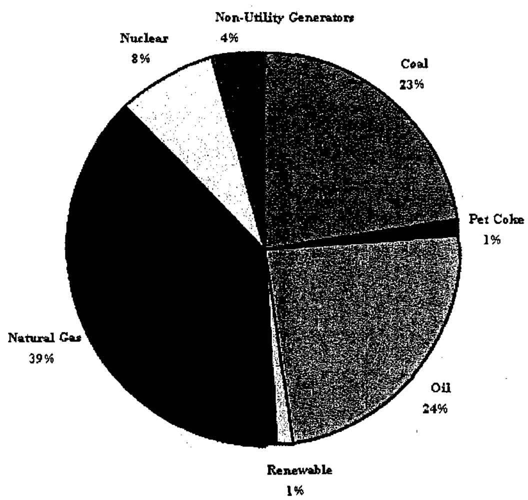
5 A gigawatt-hour ((GWH) = 1000 megawatt hours (MWH), and a MWH = 1000 kilowatt hours (KWH)) is a measure of the kilowatt demand aggregated over some time interval and represents the amount of electric energy consumed. A typical Florida residential customer will consume about 1,150 KWH per month.

have the lowest capital costs but the highest fuel costs due to lower efficiencies in converting fuel to electricity.

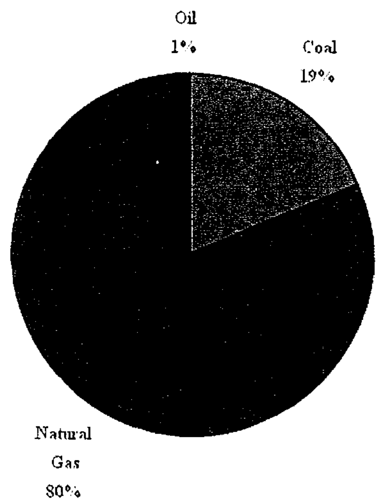
Electric utilities regularly conduct short and long-term planning exercises to ensure sufficient resources are in place to meet increasing demand. These studies determine the type of generation that is needed on the system. Baseload generation would generally take seven to ten years to receive regulatory approval and construction. Intermediate units, specifically combined cycle units, require approximately five years for approval and construction. Therefore, the ability of a utility in the short term to modify its overall fuel requirements is severely limited due to the time required to bring new generation online.

Presently, Florida's electric generating capacity is based on a variety of fuels: natural gas represents 39 percent of installed capacity, coal represents 23 percent, and oil represents 24 percent. Cumulatively, these petroleum based fuels represent approximately 86 percent of Florida's total generating capacity. Additionally, Florida's installed generating capacity includes nuclear generation (eight percent), Non Utility Generators (four percent), and renewables (one percent). In the future, new generation capacity additions are forecasted to be primarily 80 percent natural gas-fired and 19 percent coal-fired.

Installed Generating Capacity - By Primary Fuel Source



Generating Capacity Additions 2005-2014 By Primary Fuel Source



The charts above show the current installed generating capacity by primary fuel source and the projected new generation capacity additions for 2005-2014. One area of concern, which these charts highlight, is the projected growth of natural gas as the primary fuel source. While these projected new generating capacity additions are typically selected for construction based on the most cost-effective combination of capital and operating (fuel) costs, maintaining generation fuel diversity is quickly becoming a concern as well.

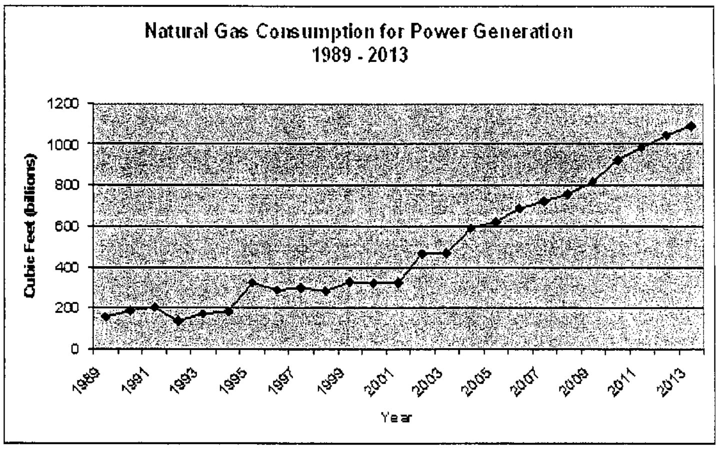
The following section specifically examines the expected trends in installed capacity and total fuel consumption for each major source of electrical power generation: natural gas, oil, coal, nuclear, interchange purchases, purchases from Non-Utility Generators (NUGs), and renewable energy sources.

Natural Gas

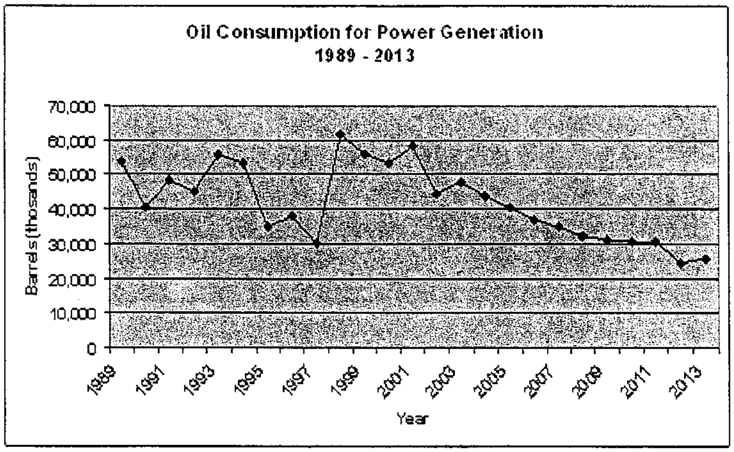
Florida's utilities continue to project a substantial increase in natural gas-fired generation. Natural gas-fired generation, currently at 29.9 percent of total statewide energy consumption, is expected to increase to 44.4 percent over the next ten years. Of the approximately 19,100 megawatts in gross capacity additions[6] projected in the state over the 2014 planning horizon, nearly 15,300 megawatts is anticipated to come from gas-fired capacity in the form of new combined cycle and combustion turbine (CT) units. Natural gas consumption forecasts do not include usage from proposed new Independent Power Producer (IPP) generating units.

Oil

Florida ranks first among all states in the amount of electricity it produces from oil. Forecasts indicate that oil-fired energy will decrease from 12.2 percent to 7.0 percent of total statewide energy



production over the next ten years. Oil-fired generation decreased substantially during the 1980s in response to rising oil prices in the 1970s. Many utilities, however, still use oil in peaking combustion turbine units as a primary and secondary fuel. Due to escalating natural gas prices, utilities have recently burned oil more frequently in baseload and intermediate combined cycle units for economic



6 Gross additions exclude capacity decreases due to unit derating, retirement, or terminating contracts.

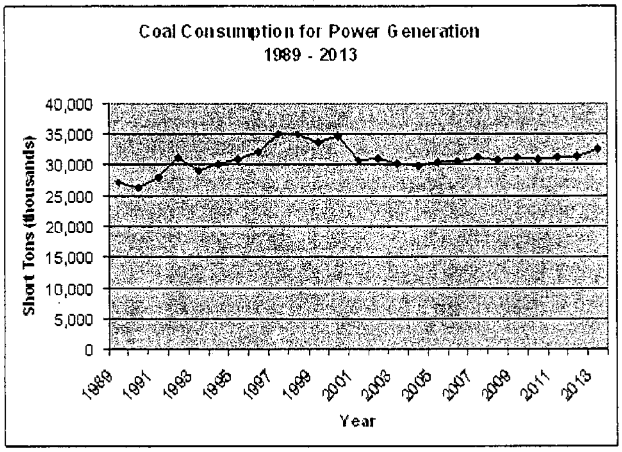
reasons. In addition, recent experience with Hurricanes Katrina and Rita illustrate the need for electric utilities to have oil available as a backup fuel when interruptions to natural gas supplies occur.

Coal

Coal generation increased substantially during the 1980s in response to the oil price increases of the 1970s. Coal plants have traditionally been operated based on low forecasts of coal prices relative to oil or natural gas. However, coal plants are capital-intensive. Stricter environmental regulations may lead to increased capital investments at coal plants. In 2004, the state's utilities forecasted increases in coal-fired capacity of approximately 1,100 megawatts from the previous year's forecast of new coal capacity to be added. The 2005 forecast shows an expected 3,786 megawatts of new coal capacity over the next ten years.

Nuclear

Nuclear generation increased considerably during the 1970s and early 1980s. Nuclear plants were



built based on low fuel price forecasts relative to oil or natural gas. However, nuclear plants are capital-intensive, take as much as ten years to certify and build and present concerns surrounding the storage and disposal of spent fuel rods. No new nuclear plants have entered service in Florida since 1983. While no utility's Ten-Year Site Plan contains proposed nuclear units, Progress Energy Florida recently announced its intention to pursue a new nuclear generating unit in Florida within the next ten years. Any nuclear additions would be operational past the 2014 planning horizon.

Interchange Purchases

Florida's utilities continue to rely on capacity and energy purchases from out-of-state utilities. Interchange purchases are typically short-term purchases of excess capacity and energy between utilities. Florida can safely import around 3,600 megawatts over the Southern Company-Florida interconnection. Approximately 2,500 megawatts of the interface is currently reserved for firm sales and for delivery of capacity from generating units owned by Florida utilities located in Southern Company's region. Approximately 1,100 megawatts remains available for non-firm, economy transactions.

Purchases from Non-Utility Generators

Non-utility generators (NUGs) build and operate power plants to satisfy contractual requirements with retail-serving electric utilities. NUGs sell firm capacity to many of Florida's utilities under long-term and short-term purchased power contracts. Forecasts indicate that the amount of NUG electricity purchased by Florida's utilities will decrease from three percent to 1.5 percent of statewide energy consumption during the planning horizon. The forecasted decrease is due to the expiration of 377 megawatts of firm purchase contracts with qualifying facilities and 339 megawatts of firm purchase contracts with renewable sources. However, once the current contracts expire, these generators will remain in place in Florida and should remain available to provide capacity and energy under new purchased power contracts with utilities.

Renewables

The renewable resources presently in the state are derived from a small amount of hydroelectric, landfill gas, biomass and waste-to-energy sources. Electric utilities and NUGs produce renewable energy in Florida. Non-utility producers of renewable energy use some of their output onsite, selling the remainder to electric utilities either under firm contracts or on an as-available basis.

Hydroelectric units at two sites in northwest Florida, one utility-owned and one operated by the Federal government, supply approximately 50 megawatts of renewable capacity. Hydroelectric generation accounts for less than 0.1 percent of Florida's generation mix. There are no planned new units due to the absence of a feasible location, as Florida's flat terrain does not lend itself to hydroelectric power.

Landfill gas provides a combined 2.5 megawatts of capacity to Gainesville Regional Utility (GRU) and Jacksonville Electric Authority (JEA). When factoring in direct use and co-generation applications, landfill gas provides nearly 40 megawatts of power statewide. Further development of landfill gas energy resources could result in an additional 68 megawatts.[7]

Florida's utilities purchase 506 megawatts of non-utility generator capacity fired by municipal solid waste, wood and wood waste, and waste heat. The scheduled expiration of contracts during the planning horizon will reduce the amount of firm renewable capacity to 167 megawatts by 2014, a decrease of 339 megawatts.

Wind turbine efficiencies have increased and costs have dropped due to research and development advances and manufacturing improvements. A recent study funded by the U.S. Department of Energy's Wind Powering America program concluded that Florida's onshore wind resources traditionally considered "marginal to good" could now be "fair to excellent." In addition, utility scale wind power generation appears to be economically viable at certain offshore and at direct coastal sites within view of the Atlantic Ocean and Gulf of Mexico.

The study further suggests that large utility-scale wind power generation is unlikely to be economically viable at inland sites more than a few hundred yards from the coastline anywhere within Florida today, with the possible exception of outer Cape Canaveral, the Panama City Beach region and the lower Florida Keys. However, there are several locations where small, distributed wind power appears feasible. Steep hills that reach 100 to 300 feet above the surrounding terrain

7 USEPA Landfill Methane Outreach Program

near electric loads and distribution lines were identified in the highlands northwest of Orlando and northeast of Tampa. In addition, coastal sites in view of open Ocean or Gulf waters have good wind resources. Mounting small wind turbines on existing cell phone towers could avoid the cost of tower construction – about half the cost of a small-wind project. To improve the economics of Florida wind energy, turbine blade design can be engineered and optimized to better match Florida's low-speed wind resources.[8]

Solar technology has been in use for years with a gradual decrease in cost and an increase in system quality and reliability. Most are building owner purchased systems and the majority of those are solar thermal (water heating) systems. Solar swimming pool heaters are the leading solar product installed in Florida.

Additionally, utility-based solar programs exist. The City of Lakeland Electric and Water Department has a solar thermal program where the utility installs and owns the solar water heater and sells the produced hot water to the customer. This program recently passed a rate impact measures test (RIM test) conducted by a consulting firm hired by the utility to evaluate conservation and demand-side management measures.

Under both state and federal law, any generator who uses renewable resources is allowed to sell any or all of its electric output to a utility for "full avoided cost." Full avoided cost is defined as the cost of the next increment of power that the utility would have incurred if it had produced the power. Thus, as electric production cost increases, renewable generators have an economic incentive to sell to the grid.

8 "Florida Wind Initiative", USDOE Wind Powering America, 2005.

Proposed New Generation Capacity[9]

Company	Plant	MW Capacity Planned	Fuel Type	Type of Plant or Units Proposed	Est. On-line Date
Hillsborough Co	Hills Co. Resource Recovery Facility	17	Garbage	Resource Recovery Facility	N/A
Florida Power & Light	SW St. Lucie Coal – 2 Units	1700	Coal	Conventional	2012, 2014
Southern Co.	Demonstration Project at Stanton	285	Coal	Integrated Gasification Combined Cycle	2010
Seminole Electric	Unit 3 at Palatka	750	Coal	Pulverized/ Conventional	2012
JEA/FMPA	Coal Project	800	Coal	Conventional	2112
Gainesville Regional Util.	Deerhaven expansion	220	Coal	Cola Fluidized Bed/Biomass/ Other	2010
Progress Energy	Hines Unit 5	540	Gas	Combined Cycle	2009
Seminole Electric	Unknown – 2 Units	364	Gas	CC	2008, 2009
Pasco Co	Pasco Co. Resource Recovery Facility	20	Garbage	RRF	N/A
Palm Beach Co	Palm Beach Co Resource Recovery Facility	28	Garbage	RRF	2010
JEA	Circulating Fluidized Bed	250	Coal	CFB	2013
Progress Energy	Hines Unit 6	540	Gas	CC	2010
Progress Energy	Central Florida Nuclear	N/A	Nuclear	Nuclear	2015
Progress Energy	Unknown CC	536	Gas	CC	2012
Tampa Electric Co	Undetermined	502	Gas	CC	2013
Seminole Electric	Unknown – 3 Units	546	Gas	CC	2013, 2014
Progress Energy	Unknown CCs – 2 Units	1,072	Gas	CC	2013, 2014
JEA/Biomass Industries Group	Unknown – 2 Units	240	E-grass	Biomass	N/A

9 Projected electrical capacity under the Power Plant Siting Act

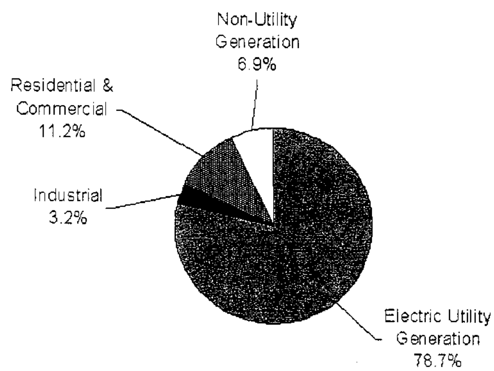
B. Current and Projected Infrastructure Needs for Production and Supply

Florida has limited native fuel resources. Energy sources native to Florida include solar, biomass and hydroelectric power in northwest Florida. All other fuels used by Florida's utilities are fossil (natural gas, oil and coal) or nuclear, which must be brought into the state by various transport systems. Coal is delivered by rail or barge, oil is delivered by tanker and nuclear fuel is delivered by rail and truck.

Natural Gas Pipeline Adequacy

Florida currently relies primarily on two major gas pipeline companies, Florida Gas Transmission (FGT) and Gulfstream Natural Gas (Gulfstream), to supply natural gas to electric utilities, industrial customers, local distribution companies and two smaller pipelines serving customers in the Panhandle (Southern Natural Gas and Gulf South). Florida Gas Transmission currently has a system pipeline capacity of 2.2 billion cubic feet per day (BCF/day), while Gulfstream has a system pipeline capacity of 1.1 BCF/day. More than 85 percent of the state's natural gas consumption is for electricity generation by utilities and non-utility generators.

Natural Gas Consumption by End-User – 2004



Forecasts indicate that electric utility generation will cause a 92 percent increase in natural gas requirements over the next ten years. Increased dependency on natural gas could affect the reliability of electric utility generation supply in Florida. The primary threat to reliability is the possibility of natural gas supply disruption. The Florida Reliability Coordinating Council (FRCC) has formed a Gas/Electricity Interdependency Task Force to determine reliability impacts and to recommend mitigating measures should reliability risks arise. The North American Electric Reliability Council (NERC) has established a Gas/Electricity Interdependency Task Force whose scope is almost identical to that of the FRCC task force. The NERC task force completed a study in May 2004, concluding in part that gas pipeline reliability can substantially affect electric generation, and that electric system reliability can have an impact on gas pipeline operations. The FRCC continues to review the recommendations made by the NERC task force to determine where to focus future analyses. The FRCC task force stated that the region has adequate pipeline capacity for reliability purposes for both current and future natural gas demand. However, the FRCC task force's conclusion assumes that the generating units that have the capability to burn oil will do so at times of peak demand. Therefore, economics may be the driving factor for any future expansion of gas pipelines.

Based on the forecasted requirements of electric utilities and other sectors, the Public Service Commission (PSC) estimates that total pipeline demand will require an average of 3.15 BCF/day by 2014. Given the current pipeline capacity of FGT and Gulfstream, sufficient capacity currently exists to serve forecasted 2014 requirements. The estimate could be understated because it relies on average daily demand rather than on maximum delivery levels specified in gas transportation contracts.

Because the 2014 forecasted pipeline capacity requirement might be underestimated based on average demand, the PSC also conducted a forecast based on the projected peak demand for gas capacity. Based on this methodology, it is estimated that by 2014, incremental pipeline capacity requirements could increase up to 1.34 BCF/day.

Florida Gas Transmission

FGT operates 5,000 miles of pipeline nationwide, 3,300 miles of which are in Florida. Six expansions have occurred since its inception in 1959, which have increased the pipeline's capacity from its original 0.278 BCF/day to its current 2.2 BCF/day. In October 2005, FGT filed an application with the Federal Energy Regulatory Commission (FERC) seeking authority to construct its Phase VII Expansion Project. This project involves the construction of 33 miles of 36-inch diameter pipeline looping and the installation of 9,800 horsepower of compression. The expansion will provide approximately 0.16 BCF/day of additional capacity to transport natural gas from a connection with Southern Natural Gas Company's proposed Cypress Pipeline project.

Gulfstream

Gulfstream placed Phase I of its two-phase natural gas transmission system into service in 2002. Phase I, with a capacity of 1.1 BCF/day, crosses the Gulf of Mexico between Pascagoula, Mississippi and Manatee County, Florida with more than 430 miles of 36-inch pipe. In February 2005, Phase II, a 110-mile extension to Florida's east coast, entered service to serve Florida Power and Light's gas-fired generating units at the Martin and Manatee plant sites.

Cypress

Southern Natural Gas has proposed expanding its existing interstate natural gas pipeline system between Port Wentworth, Georgia and an interconnection with FGT's system near Jacksonville, Florida. Project construction will occur in three phases. Phase I includes the initial pipeline of 165 miles of 24-inch diameter pipe. Phase II and III will consist of additional compression and looping. The source of natural gas will be Southern Natural Gas's Elba Island liquefied natural gas (LNG) facility near Savannah, Georgia. The Cypress pipeline will have the ability to flow gas between Florida and Georgia in both directions. In addition, the pipeline will provide Florida with a new, geographically diverse source of gas that will help mitigate supply disruptions caused by natural disasters such as hurricanes. In 2005, the PSC approved Progress Energy Florida's long-term contract to purchase gas supply on the Cypress pipeline. Phase I of the pipeline is expected to be in service in 2007, with Phase II and III becoming operational in 2009 and 2010, respectively.

Bahamas LNG Projects

Two consortia have proposed pipeline projects to transport LNG from the Bahamas to Florida. Two of the projects, the Tractabel Calypso Project and the AES Ocean Express Project, have received FERC approval, granting both projects a Presidential Permit to construct. The third project, the El Paso Seafarer Pipeline System, filed its certificate application with the FERC in November 2004, and the application is pending. These projects must first receive approval from the Bahamian government before construction can begin. The applicants have not yet contracted with an anchor utility customer to purchase the gas.

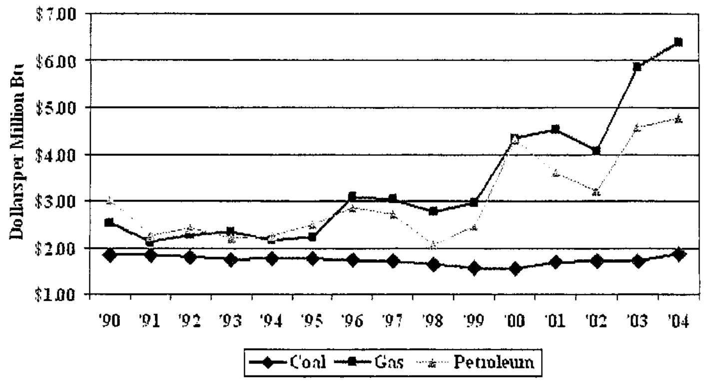
c. Current and Projected Consumer Costs

Electricity rates include base rates that include costs for electric generating capacity, transmission and distribution facilities, operation and maintenance expenses and administrative expenses such as billing. Rates are a function of the type of generating units on a utility's system, the costs to operate those units, including fuel, and the cost to transmit and distribute power to consumers.

Total Monthly Bill for 1,000 Kilowatt Hours – Residential Electric Service (For Florida Investor-Owned Utilities) Effective January 1, 2006				
	Florida Power and Light Company	Progress Energy Florida, Inc.	Tampa Electric Company	Gulf Power Company
Base Rate	$38.12	$41.18	$51.92	$49.30
Fuel Cost Recovery	$58.41	$49.79	$54.35	$30.92
Energy Conservation Cost Recovery	$1.42	$0.76	$1.69	$0.88
Environmental Cost Recovery	$0.26	-$3.72	$0.62	$3.64
Capacity Cost Recovery	$6.03	$3.56	$9.93	$2.72
Storm Damage Cost Surcharge	$1.65	n/a	$3.61	$2.71
Gross Receipts Tax	$2.72	$2.74	$2.74	$2.31
Total Monthly Bill	$108.61	$109.56	$109.61	$92.48

Fuel costs incurred by the electric utilities to generate needed power are directly passed through to customers. The cost of fuel does not have any "markup" or generate earnings for the utilities.

Delivered Cost of Coal, Natural Gas & Petroleum to Florida Electric Utilities
1990-2004



The cost of renewable fuels remains relatively high compared with traditional hydrocarbon fuels, but advancements in renewable technologies have made some of these fuels more cost-competitive. The following chart compiled from several sources provides the estimated consumer cost per kilowatt hour of select renewable fuels.

Electric Power Consumer Costs ($/KWh)[10]	
Renewable Energy Source	Current Price
Hydrogen	0.26
Solar Thermal (for water heating)	0.054
Solar Photovoltaic (PV)	0.18 - 0.32
Biomass	0.08 - 0.12
Wind	0.04 - 0.06
Landfill Methane	0.02 - 0.06
Waste-to-Energy (WTE)	0.04 - 0.15

D. Current Regulatory Oversight of Electric Utilities

Florida Public Service Commission (PSC)

The PSC has authority to ensure the provision of adequate, reliable, reasonable cost electricity to consumers. The PSC has specific authority under Chapter 366, Florida Statues, to regulate the rates and service of investor-owned electric utilities in the state. It also has authority to oversee the reliability of the electric grid, to determine the need for new electric generating facilities (Section 403.519, F.S.), to establish utility conservation goals (Sections 366.80-.82, F.S.) and oversight of the safety of electric facilities (Section 366.04, F.S.).

The PSC has authority to set the rates of natural gas utilities that provide service to end-use customers. Proposed intrastate natural gas pipelines must receive an affirmative determination of need from the PSC prior to construction (Section 403.9422, F.S.) Inspection of natural gas facilities to help ensure safe operations is also conducted by the PSC.

10 Hydrogen figure derived from actual operating data reported to the Florida Energy Office. Solar figures provided by the Florida Solar Energy Center. Wind figure provided by National Renewable Energy Laboratory. Remaining figures derived from the 2003 report titled "An Assessment of Renewable Electric Generating Technologies for Florida".

Department of Environmental Protection (DEP)

Power Plants

The Power Plant Siting Act is a centralized, coordinated licensing process encompassing the permitting and other authorizations, including proprietary interests, of all state, regional, and local agencies in the jurisdiction of which an electric power plant is proposed to be located. The Act provides for a single certification (license) for those electric power plants, as defined by the Act, which are steam or solar powered, 75 megawatts or greater and are constructed after October 1, 1973. Only electric utilities as defined by the Act may apply for certification. The process includes mandatory land use and certification hearings by an administrative law judge, a Determination of Need by the PSC, with ultimate approval/denial authority vested in the Siting Board (Governor & Cabinet). The DEP coordinates the process.

Transmission Lines

The Transmission Line Siting Act is a centralized, coordinated licensing process encompassing permitting and other authorizations, including proprietary interests, of all state, regional, and local agencies in the jurisdiction of which a transmission line is proposed to be located. The Act provides for a single certification (license) for transmission lines. Transmission lines subject to the Act are those that are 230 kilovolts or greater, 15 miles or more in length and cross a county line. The process includes a mandatory hearing by an administrative law judge, a Determination of Need by the PSC, with ultimate approval/denial authority vested in the Siting Board (Governor & Cabinet). The DEP coordinates the process.

Natural Gas

The Natural Gas Pipeline Siting Act is a centralized, coordinated licensing process encompassing permitting and other authorizations, including proprietary interests, of all state, regional, and local agencies in the jurisdiction of which a natural gas pipeline is proposed to be located. Natural gas pipelines subject to the Act are those that are 15 miles or more in length and cross a county line. There are exemptions for pipelines that are designated for local distribution only and for pipelines that have received a certificate of public convenience and necessity from FERC. Most pipelines do receive a certificate of public convenience and necessity. As a result, no pipeline has been certified yet under the Act. The process includes a mandatory hearing by an administrative law judge, a Determination of Need by the PSC, with ultimate approval/denial authority vested in the Siting Board (Governor and Cabinet). The DEP coordinates the process.

Environmental Impacts

The DEP administers resource protection and pollution control permitting processes for all federal environmental permits that are delegated to or approved by the State. Federally delegated or approved permit programs include air permits such as Title V and Prevention of Significant Deterioration permits, water permits including National Pollutant Discharge Elimination System permits and Underground Injection Control. The DEP also administers state environmental permits for facilities that are not subject to the siting acts. The DEP also regulates any impacts to State owned lands.

Other State Regulatory Authorities

Power generation associated with some sources of renewable power is regulated through a variety of delegated authorities. The following section is intended to provide highlights of regulatory oversight but may not be all-inclusive:

Solar

Regulatory standards are tied to the type of buildings that consider solar technology, and there are few restrictions on how the technology is utilized or requirements for its use. All solar equipment sold in Florida must be certified by the Florida Solar Energy Center (FSEC) pursuant to Section 377.705, F.S. Certifications are issued by FSEC and the Solar Rating and Certification Corporation. Contractors are trained and tested by the FSEC and must obtain licensure through the Florida Department of Business and Professional Regulation pursuant to Section 489.105, F.S. As established by the PSC, interconnection of small photovoltaic systems (up to ten kilowatts) is allowed.[11] The interconnection requests are processed by the utility company, who will accept all requests meeting the standards of the application process. Building codes for installation of solar systems are regulated by the Department of Community Affairs.

Biomass

Biomass covers a broad array of fuel sources and different permitting may be applicable depending on the source utilized. Federal regulatory standards for biomass are administered by the United States Environmental Protection Agency through the authority of the Biomass Research and Development Act of 2000. In Florida, the DEP regulates biomass energy under the authority of the Clean Air Act.

Waste-to-Energy

Waste-to-energy is regulated by the DEP, which also permits waste-to-energy facilities.

Wind Energy

Florida Statues regarding the Renewable Energy Access Laws require that ordinances, deed restrictions, covenants or similar binding agreements cannot prohibit solar equipment use (and other renewable energy technologies). As such, regulatory oversight for wind energy is largely a local government issue.

E. Florida's Energy Efficiency and Alternative Energy Initiatives

Demand-side management (DSM) reduces customer peak demand and energy requirements, resulting in the deferral of need for new generating units. Utilities have offered DSM programs since 1980 under the requirements of the Florida Energy Efficiency and Conservation Act. The Act emphasizes reducing the growth rate of weather-sensitive peak demand, reducing and controlling the growth rate of electricity consumption and reducing the consumption of expensive resources such as petroleum fuels. To meet these objectives, the PSC sets numeric conservation goals and utilities develop and implement DSM programs to meet these goals.

Overall, Florida's utilities have been successful in meeting the overall objectives of the Act. Since 1980, utility conservation programs have reduced statewide summer peak demand by 4,951

11 Section 25-6.065, Florida Administrative Code

megawatts, winter peak demand by 5,511 megawatts and annual energy consumption by 5,488 gigawatt-hours. By 2014, DSM programs are forecasted to reduce summer peak demand by 5,563 megawatts, winter peak demand by 6,068 megawatts, and annual energy consumption by 6,883 gigawatt-hours.

State of Florida - Estimated Savings from Electric Utility DSM Programs[12]		
DSM Savings	**2005**	**By 2014**
Summer Peak Demand	4,951 MW	5,563 MW
Winter Peak Demand	5,511 MW	6,068 MW
Annual Energy Consumption	5,488 GWh	6,883 GWh

Numeric Conservation Goals and DSM Plans

The Florida Energy Efficiency and Conservation Act requires that all investor-owned utilities and any municipal or cooperative utility with annual energy sales of at least 2,000 gigawatt-hours as of July 1, 1993 meet numeric conservation goals set by the PSC. Seven Florida utilities are subject to this requirement: Progress Energy – Florida, Florida Power & Light, Gulf Power, TECO, Florida Public Utilities Company, JEA, and Orlando Utilities Commission.

The PSC set new numeric demand and energy goals for these seven utilities in July 2004. The new numeric goals were generally lower than the previous goals set by the PSC in 1999 for three primary reasons: (1) the Florida Building Code contains increased minimum energy efficiency levels, limiting the amount of incremental savings from utility sponsored programs; (2) many utility DSM programs have reached a saturation in participation levels; and (3) the relatively low cost of new generating units has reduced the cost-effectiveness of several DSM programs.

Energy Conservation Cost Recovery

Investor-owned utilities have the opportunity to recover prudently incurred expenditures associated with PSC-approved DSM programs through the Energy Conservation Cost Recovery Clause (ECCR). Since 1981, Florida's investor-owned utilities have collected approximately $4.15 billion through the ECCR, with nearly $2.54 billion recovered in the last ten years. Annual ECCR expenditures have stabilized at just under $250 million per year over the past six years for two primary reasons: 1) DSM programs have reached saturation in participation levels, and 2) DSM program cost-effectiveness continues to decline due to the lower cost of new generating units. However, as utility plans include more solid fuel generation options, DSM program cost-effectiveness will improve.

Federal and State Solar Energy Initiatives

To conserve energy and reduce electricity bills, the State is providing 150 solar water heaters to residents in 20 underserved communities throughout the state. Named *Front Porch Sunshine*, Florida is the first in the nation to install solar energy technology in weatherized, low-income homes.

Florida schools are using the state's free supply of sunshine to light classrooms and the imaginations of students. Florida's *SunSmart Schools Program* is installing 29 solar electric systems in schools

12 Demand savings are cumulative from 1980. Energy savings are on an annual basis.

throughout the state. The program combines State funding with private partnerships to provide clean energy and science education. The electric power generated by the system is used to power the school's classrooms, with excess energy returned to the local power grid. The system also provides an on site classroom for students to learn more about solar power and the benefits of energy conservation.

SunBuilt is the latest program to expand solar energy technology in communities throughout Florida. A partnership between DEP, the Florida Home Builders Association and the Florida Solar Energy Research and Education Foundation, *SunBuilt* provides rebate checks to home builders who install solar hot water heaters in newly constructed homes. *SunBuilt* Builders are eligible to receive rebates for each solar equipped home constructed. The reliable, low-maintenance solar systems use the sun's energy, instead of electricity, to heat water. A solar collector installed on the roof holds water that is heated by the sun. A traditional water heater serves as a backup supply of hot water on overcast or rainy days. Benefiting both the economy and the environment, the amount of energy generated annually by a single solar water heater is equal to two barrels of oil, lessening the state's dependence on petroleum imports.

Federal and State Energy Efficiency Initiatives

Florida's 35 million hotel guests can now opt to take a break at a *Green Lodge* – a new State designation that recognizes environmentally-friendly hotels and motels. The voluntary program establishes environmental guidelines for hotels and motels to conserve natural resources and prevent pollution. Hotels and motels reduce costs and earn designation by investing in simple and innovative 'green' practices that conserve water, save energy and reduce waste.

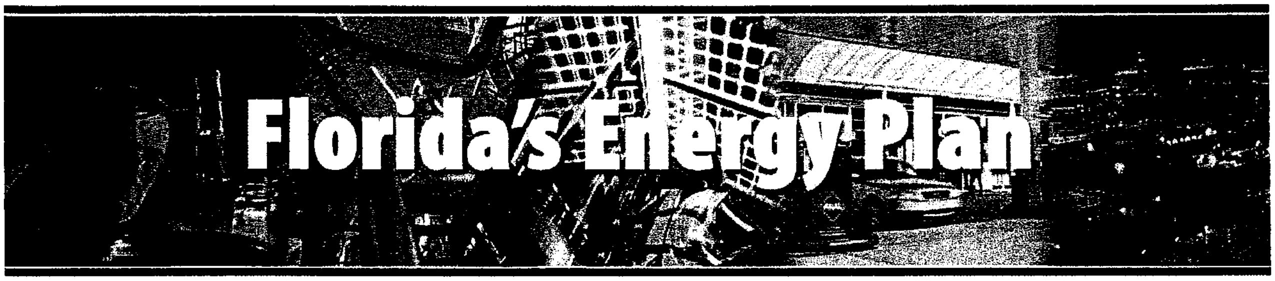
Rebuild America is a growing network of community-driven voluntary partnerships that foster energy efficiency and renewable energy in commercial, government and public-housing buildings. For example, the University of Central Florida is outfitting three buildings on campus with energy efficient technologies. The project will dramatically reduce energy consumption in these buildings, with energy savings reinvested in the project for wider application across campus. In addition, school districts in Florida, North Carolina and Tennessee were selected by the National Energy Foundation to receive energy education materials and teacher training. In school year 2003-04, four school districts with more than 19 million square feet of building space reported saving 18,346,495 kilowatt hours and nearly $1.2 million from energy conservation practices.

In 2004-05, the *Florida Energy Conservation Assistance Program* provided energy surveys of more than 9,717,000 square feet of building space for state/municipal governments, small businesses, agricultural and hospitality in Florida. The surveys identified more than $11.8 million of possible energy savings for the clients involved.

Federal and State Hydrogen Initiatives

In July 2003, Governor Jeb Bush launched "H2 Florida," a statewide initiative to accelerate the commercialization of hydrogen technologies, spur investment and economic opportunity and safeguard the nation's natural resources. H2 Florida partners the State of Florida with industry, governments and academia to showcase hydrogen technologies and stimulate a consumer market for cleaner, sustainable sources of energy. The State's commitment supports that of the White House's proposed investment of $1.7 billion over five years to develop hydrogen-powered fuel cells, hydrogen infrastructure and advanced automotive technologies.

Florida has 28 hydrogen demonstration projects underway and seven state universities are conducting more than 100 hydrogen research and development projects. In 2003, the Florida Energy Office and Florida Power and Light installed a fuel cell at Hugh Taylor Birch State Park. Since that installation, the Florida Energy Office has installed fuel cells at North Port High School and Homosassa Springs State Park. Additionally, the DEP has purchased 12 fuel cells to provide backup power at their District and Branch Offices statewide.



III. Florida's Ability to Produce, Store and Distribute Transportation Fuel

A. Current and Projected Supply and Demand for Transportation Fuel

Transportation is Florida's second largest energy use sector comprising more than a third of the total energy used. Florida depends almost exclusively on other states and nations for supplies of oil and gasoline, producing less than one percent of the nation's crude oil production annually. Florida consumes 8.6 billion gallons of gasoline per year, and consumption is growing by 300 million gallons per year.[13]

Current transportation fuel needs are approximately 28.1 million gallons per day[14], not including aviation fuels. Motor gasoline and diesel fuel make up more than 87 percent of Florida's transportation energy costs, with aviation fuel accounting for less than 10 percent.[15]

In ten years, Florida's transportation fuel demand is expected to increase to 32.3 million gallons per day, assuming a 15 percent increase in the state's population.[16]

Refined Petroleum Products

Florida's reliance on imported petroleum products, in addition to its anticipated growth in consumption during the next decade, underscores a potential vulnerability to interruptions in fuel supply delivery during natural or man-made disasters.

Ethanol

The demand for ethanol is driven largely by the federal Energy Policy Act of 1992 (EPAct 1992), which required that public and private vehicle fleets operated within selected Metropolitan Statistical Areas (MSA) acquire and operate Alternative Fuel Vehicles (AFV). Florida contains nine designated MSAs in which the EPAct 1992 AFV standards apply. There are seven ethanol fueling stations in Florida, all of which are restricted for private fleet usage for EPAct 1992 compliance. The demand for ethanol-based fuels is expected to grow in coming years as at least one major automobile manufacturer (Ford Motor Company) has announced plans to increase production of AFVs by 2010.

Florida currently has no operational ethanol plants in the state. Florida meets this demand for ethanol by imports from refineries outside of the state. Ethanol stations are subject to fire and building code requirements, regulated by the National Fire Protection Association and the Florida Department of Community Affairs respectively. Depending upon the size of the facility, additional

13 Florida Department of Revenue

14 Daily consumption based on data from Florida Department of Revenue.

15 Florida's Energy Future, January 2003.

16 Assumes an average of 1.5% growth annually for the next ten years, based on U.S. Census Bureau population trend from 2000-2004.

permits for storm and wastewater and air emission permits may be required from DEP.

Biodiesel [17]

The total "dedicated" biodiesel production capacity in the United States is approximately 180 million gallons per year. Another 100 million gallons is projected to be online by May 2006 and an additional 470 million gallons are planned nationwide.

In Florida, a multi-feedstock biodiesel plant in Lakeland has the capacity to produce 18 million gallons annually and will eventually produce up to 30 million gallons. Two additional companies have set up biodiesel distribution facilities at the Port of Tampa and Port Everglades.

Hydrogen

Florida's current hydrogen capacity is less than 20 gallons of gasoline equivalent per day (gge/day). Florida currently has one hydrogen energy station in operation, two stations in the construction and permitting stages and two stations in the planning phase. Once permitted and constructed, the two additional hydrogen fueling stations will provide more than 130 additional gallons of gas equivalent per day.

Once all five hydrogen stations are installed and operating, they will meet the demand of 15 vehicles - approximately 290 gallons of gas equivalent per day.

B. Current and Projected Infrastructure Needs for Production and Supply

As the demand for transportation fuels increases over the coming years, Florida's infrastructure for producing, storing and transporting that fuel to market will also increase. The following table summarizes Florida's current and projected transportation fuels capacity.

Transportation Fuel Capacity (million gallons)	Current 2005	Projected
Gasoline – Bulk Storage	342[18]	
Gasoline – Retail Storage	187[19]	
Diesel – Bulk Storage	141	
Diesel – Retail Storage	24	
Ethanol	0	80 MMG/Yr
Biodiesel	18 MMG/Yr	66 MMG/Yr
Hydrogen	3000 gge[20]	

17 National Biodiesel Board

18 Represents bulk storage capacity at the ports. Volume derived from data reported to DEP, Bureau of Petroleum Storage Systems, adjusted down by 20% to account for unused min/max levels kept in the tanks.

19 Represents storage capacity at retail stations. Volume derived from data reported to DEP, Bureau of Petroleum Storage Systems, adjusted down by 10%.

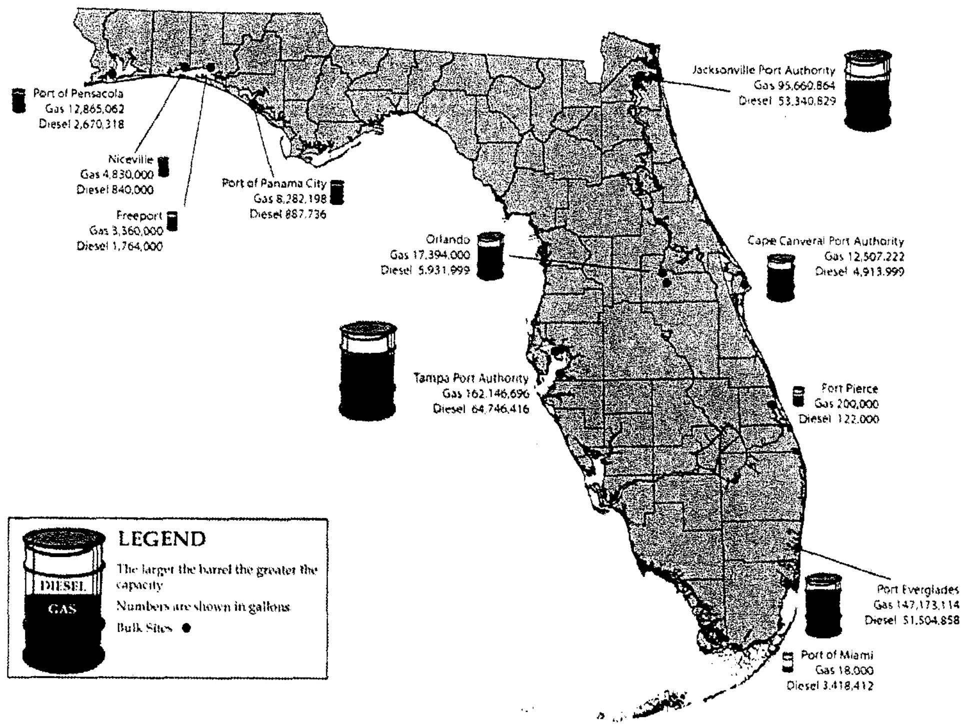
20 gge = gallons of gasoline equivalent.

In-state Oil Production

Florida's oil production capability is approximately 10,000 barrels per day, or 120 million gallons of gasoline per year. Production has been steadily declining for the past few decades due to the declining economic efficiency of the state's oil fields. Crude oil production within Florida is negligible in meeting the state's current or future demand for motor fuel as Florida does not contain any native refinery capacity. Crude oil is moved via pipeline to refineries outside the state for processing.[21] Additional oil production within Florida is not expected to occur within the planning horizon.

Refined Petroleum Products

Florida receives 98 percent of its fuel by sea via barge and tanker ship into seven ports. Ninety percent is received into three ports: the Port of Tampa, the Port of Jacksonville and Port Everglades. The remaining two percent is supplied from out-of-state via tanker truck. Fuel is supplied by domestic and international refineries as well as the pipeline spur in Bainbridge, Georgia.



From bulk storage, fuel is distributed by approximately 1,000 tanker trucks under various commercial arrangements to more than 9,200 retail gas stations in the state.[22] Fuel distribution fluctuates based on the supply and demand for fuel and the business objectives of petroleum companies and suppliers.

21 Sources: Oil and Gas Annual Production Reports, Florida Geological Survey, 2004, and the Florida Petroleum Council, Fuel Fact Sheet

22 Florida Petroleum Council

Ethanol

While there are currently no ethanol production plants in Florida, there is the potential for two or three plants in southwest Florida becoming operational over the next few years with a combined annual production capacity of 80 million gallons.

Florida's seven ethanol fueling stations are not open to the public and serve organizational fleets such as the Department of Transportation.

Biodiesel

Annual biodiesel production capacity in Florida is 18 million gallons and is anticipated to grow to 30 million gallons in the near future. Storage capacity for imported biodiesel is expected to grow to over 36 million gallons within the next year.

The National Biodiesel Board currently lists nine companies as distributors of biodiesel throughout Florida. Biodiesel is not readily available through retail fueling stations.

Hydrogen

Nationally, approximately 20 hydrogen stations providing fuel to controlled fleets are in operation. Florida currently has one station in operation, two stations in the construction and permitting stages and two stations in the planning phase.

- Existing Hydrogen Station in Operation
    - o BP facility on State Road 426 in Oviedo
        - Designed to support controlled fleet of five fuel cell vehicles
        - Generation capacity: <20 gge/day
- Hydrogen Stations Under Construction/Permitting
    - o Chevron Hydrogen Company facility at Boggy Creek Road and Tradeport Drive in Orlando
        - Designed to support controlled fleet of four shuttle buses
        - Generation capacity: <120 gge/day
    - o Hydrogenics facility at the Orlando International Airport
        - Designed to support controlled fleet of two baggage carriers
        - Generation capacity: <16 gge/day
- Planned Hydrogen Stations
    - o Supplier To Be Determined on International Drive in Orlando
        - Designed to support controlled fleet of 4 shuttle buses
        - Generation Capacity: <120 gge/day
    - o Supplier To Be Determined at NASA/Kennedy Space Center in Cape Canaveral
        - Designed to support controlled fleet of two shuttle buses
        - Generation Capacity: <60 gge/day

C. Current and Projected Consumer Costs

Transportation Fuel Consumer Costs ($/gallon)	Current 2005
Diesel	2.30 - 2.60
Ethanol	1.22 - 1.60
Biodiesel	2.40 - 3.70
Hydrogen	$8.56/gge

Ethanol is sold into the gasoline blending market where it competes with other oxygenates, octane components and gasoline. As such, ethanol prices are highly correlated with the price of gasoline and gasoline blending components. Additionally, biodiesel is sold into the diesel blending market and correlates with the price of diesel. Availability of hydrogen is limited to specific fleet applications.

D. Current Regulatory Oversight

The following section is intended to provide highlights of regulatory oversight but may not be all-inclusive.

Refined Petroleum Products

- The U.S. Environmental Protection Agency regulates emissions associated with the combustion of petroleum products and regulates the sulfur content in the fuel.
- The DEP certifies the installation of above ground and underground storage tanks.
- The Florida Department of Agriculture and Consumer Services regulates fuel quality, maintains blending requirements, sets the Reid Vapor Pressure requirements and is responsible for the weights and measures associated with dispensers at retail stations.
- The Florida Department of Revenue applies taxes to petroleum products.
- The Florida Department of Transportation is responsible for all regulation associated with on road distribution including truck weights, tanker truck storage requirements, operational hours, etc.
- The Florida Department of Community Affairs is responsible for all building codes associated with retail facilities and the construction of any structures.
- The Florida Department of Financial Services is responsible for all hazardous material requirements, including fire and safety codes.

Hydrogen Refueling Stations

Codes for permitting both stationary fuel stations and hydrogen motor fuel dispensing stations are currently being developed. The report "The Regulator's Guide to Hydrogen Development" details the methodology to be used in creating these guidelines and was developed through a collaborative effort involving the National Fire Protection Association (NFPA), the International Code Council (ICC), Pacific Northwest National Laboratory and the National Renewable Energy Laboratory. Stationary hydrogen refueling facilities must meet NFPA codes and building codes. Building codes are regulated by the Florida Department of Community Affairs, while the fire codes are created through the NFPA. The Vehicular Fuel Systems Code of 2006, Chapters 12.1

– 14.13.9, is the specific reference for the NFPA rules regarding hydrogen fueling stations.

Ethanol Refueling Stations

Ethanol stations are subject to fire and building code requirements.

Owners or operators of vehicles powered by alternative fuel are required to obtain a valid Alternative Fuel Use Permit from the Florida Department of Revenue. This decal is in lieu of the excise tax on gasoline. Refueling stations are not allowed to fuel an alternative fuel vehicle that does not display the appropriate decal. State and local government alternative fuel vehicle fleets are exempt from paying the decal fee.

Biodiesel Refueling Stations

Pursuant to Chapter 206, F.S., biodiesel is not categorized as an alternative fuel, but as a diesel fuel and is subject to all regulatory issues cited for refined petroleum products. The Florida Department of Revenue alternative fuel decals do not apply to biodiesel.

E. Fuel Efficiency and Alternative Fuel Initiatives in Florida

Florida has the fourth largest number of registered hybrids in the nation. Florida's state government agencies have committed to purchase alternative fuel and clean energy vehicles. More than 22 percent of DEP's fleet is comprised of "green" transportation with more than 90 hybrid vehicles and more than 290 alternative fuel vehicles. The State of Florida's entire vehicle fleet comprises just over 19,000 cars and light trucks. Of that amount, 107 are hybrid and 1,491 are alternative fueled vehicles.[23] Since its inception in 1993, the U.S. Department of Energy's Clean Cities Program -- with 88 coalitions nationwide, including two in Florida -- has helped conserve enough petroleum to fuel two million cars for a year.

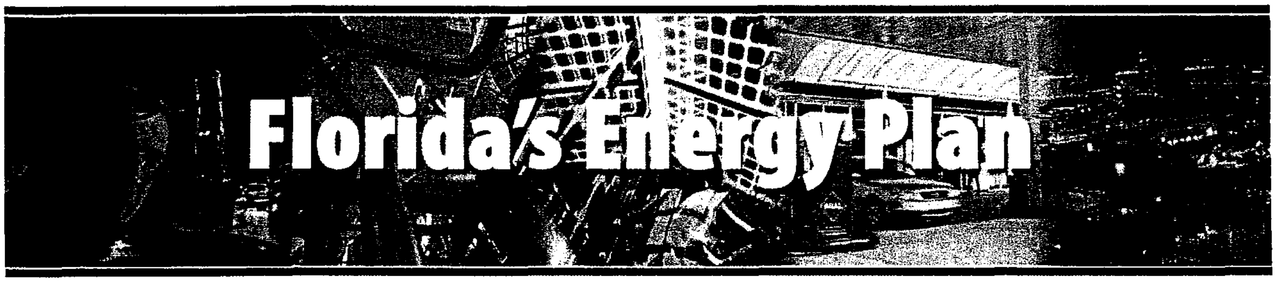
The U.S. Department of Energy's Clean Cities Program is advancing the economic, environmental and energy security of the United States by adopting practices that reduce petroleum consumption in the transportation sector. Clean Cities carries out this mission through a network of volunteer coalitions, which develop public/private partnerships to promote alternative fuels and vehicles, fuel blends, fuel economy and hybrid vehicles.

Florida has 28 hydrogen demonstration projects underway and seven state universities are conducting more than 100 hydrogen research and development projects. By 2006, Florida aims to establish metro-Orlando as a "hydrogen hub," building four hydrogen energy stations to supply hydrogen vehicle fleets in Central Florida.

In September 2005, Florida received its first fleet of hydrogen vehicles. Five Ford Focus Fuel Cell vehicles were delivered to the DEP and Progress Energy Florida. The vehicles are in use at Wekiva Springs State Park, DEP's Central District and at Progress Energy's Longwood facility and will also be showcased in regional alternative and clean energy conferences, summits and events.

In January 2006, the DEP, Ford, Hydrogenics, Tug Technologies, and Delta Airlines expect to begin demonstrating hydrogen baggage carriers at the Orlando International Airport. Additionally, in the fall of 2006, DEP, ChevronTexaco and Ford will provide eight hydrogen shuttle busses to the Orlando-area for use in the tourism industry.

23 Florida Department of Management Services



IV. Overview of Florida Statutes

Currently, Florida law addresses energy concerns with several distinct statutory chapters. These statutes provide the institutional structure for the regulation and implementation of energy policy in the State of Florida. Responsibilities for energy regulation and policy implementation are divided between a legislative commission, the PSC and two executive level agencies: the Florida Department of Community Affairs and the DEP.

Chapter 186, F.S.

Chapter 186, F.S., promotes intergovernmental coordination and the effective allocation of resources by outlining a coordinated planning process. Section 186.801, F.S., highlights the requirement that all regulated utilities submit a Ten-Year Site Plan to the PSC. This document estimates a utilities power-generating needs and the general location of its proposed power plant sites.

Chapter 350, F.S.

Chapter 350 F.S. provides the enabling legislation for the utility regulatory body, the PSC. This chapter contains the statutory provisions under which the PSC operates including how commissioners are chosen and confirmed, the purview and statutory authority of the commission, and the funding mechanism through the Florida Public Service Regulatory Service Trust Fund.

Chapter 366, F.S.

Chapter 366, F.S., governs the PSC's jurisdiction over electric and gas utilities.

This statute gives the PSC authority over five broad areas for all electric utilities in the state, including municipals and rural cooperatives. The chapter provides the source for the Commission's rate making authority, including cost recovery. It also specifically addresses cogeneration and small power production, the requirements of the Florida Energy Efficiency and Conservation Act, ensures the development and maintenance of a reliable and coordinated power grid, as well as electric safety requirements.

This chapter directs the PSC to establish and maintain continuous liaison with all other appropriate state and federal agencies whose policy decisions and rulemaking authority affect those utilities over which the commission has primary regulatory jurisdiction.

Chapter 368, F.S.

Chapter 368, F.S., authorizes the establishment of rules and regulations covering the design, fabrication, installation, inspection, testing and safety standards for installation, operation and maintenance of gas transmission and distribution systems, including gas pipelines, gas compressor stations, gas metering and regulating stations, gas mains, and gas services up to the outlet of the customer's meter set assembly, gas-storage equipment of the closed-pipe type fabricated or forged from pipe or fabricated from pipe and fittings and gas-storage lines.

This Chapter also creates the rate making authority of the PSC for natural gas transmission companies for any service relating to the transmission or sale of natural gas in the state. The section applies only to facilities located wholly within this state for the transmission or delivery for sale of natural gas. Local distribution pipelines are exempt.

Chapter 377, F.S.

Chapter 377, F.S., addresses the regulation, planning and development of the energy resources of the state. It is the policy of the State of Florida to conserve and control the natural resources of oil and gas to prevent waste of natural resources and to safeguard the health, property and public welfare of the citizens of the state.

Chapter 377, F.S., specifically addresses the funding by electric utilities of local governmental solid waste facilities that generate electricity, the Solar Energy Standards Act of 1976, functions of the Florida Department of Community Affair's Energy Emergency Contingency Plan and Federal and State Conservation Programs.

Finally, Chapter 377, F.S., provides the language for the duties and activities of the Florida Energy Office.

Chapter 403, F.S.

Chapter 403, F.S., recognizes that the predicted growth in electric power demand requires the development of a procedure for the selection and utilization of sites for electrical generating facilities and the identification of a state position with respect to each proposed site. Thus, Chapter 403, F.S., outlines the requirements of the Florida Electrical Power Plant Siting Act which applies to any steam or solar electrical generation facility except those that are less than 75 megawatts.

This statute also provides an exclusive forum for determination of need for an electrical power plant. Chapter 403, F.S., addresses electric power transmission concerns by outlining the Transmission Line Siting Act, which applies only to a transmission lines that operates at 230 kilovolts or more, while transmission lines which are less than 15 miles in length or which do not cross a county line are exempt and by providing a process for the determination of need for transmission lines. Chapter 403, F.S., also creates the Natural Gas Pipeline Siting Act. The DEP also regulates electric and magnetic fields from electrical transmission lines under the provisions of sections 403.061(30) and 403.523(14), F.S.

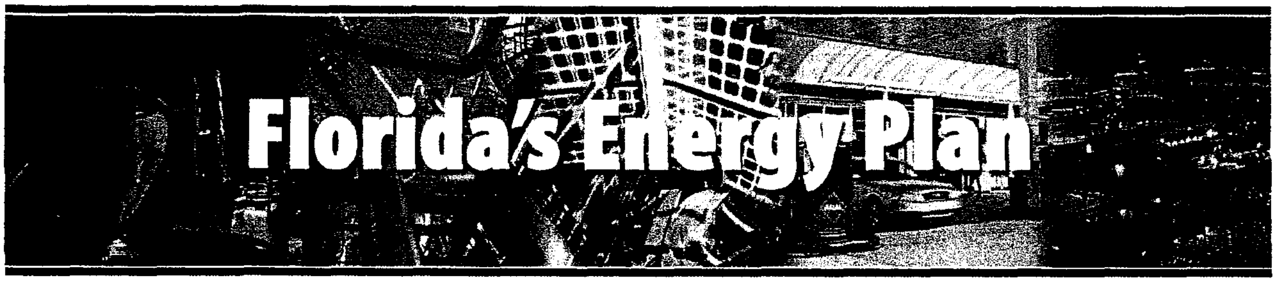
Chapter 553, F.S.

Chapter 553, F.S., addresses thermal efficiency standards by instructing the Florida Department of Community Affiars to provide a thermal efficiency code to provide for a statewide uniform standard for energy efficiency in the thermal design and operation of all buildings statewide, consistent with energy conservation goals, and to best provide for public safety, health, and general welfare.

Chapter 553, F.S., also specifies that the Florida Building Commission shall adopt the Florida Energy Efficiency Code for Building Construction within the Florida Building Code, and shall modify, revise, update, and maintain the code to implement the provisions of this thermal efficiency code and amendments thereto, in accordance with the procedures of Chapter 120, F.S. The DCA shall, at least triennially, determine the most cost-effective energy-saving equipment and techniques available and report its determinations to the commission, which shall update the code to incorporate such equipment and techniques.

Chapter 553, F.S., addresses energy efficiency by providing statewide minimum standards for energy efficiency in certain products, consistent with energy conservation goals. The standards are required to be based on feasible and attainable efficiencies which will reduce Florida's energy consumption growth rate and the growth rate of energy demand.

Finally, Chapter 553, F.S., outlines the Building Energy Efficiency Rating System to provide for a statewide uniform system for rating the energy efficiency of buildings.



V. Recommendations for Electric Power Generation

Diversification Recommendations

Recommendation #1: Streamline and expedite the siting and permitting of generation sources by revising the provisions of the Florida Electrical Power Plant Siting Act by 2006, reduce the average processing time for new power plants by three months while maintaining opportunities for public input and protecting Florida's environment. (Department of Environmental Protection, Siting Board)

The Power Plant Siting Act (PPSA) is a centralized, coordinated licensing process encompassing the permitting, land use and zoning, and proprietary interests of all state, regional, and local agencies in the jurisdiction of which an electric power plant is proposed for location. The PPSA provides for a single certification (license) for those electric power plants, as defined by the PPSA, which are steam or solar powered, 75 megawatts or greater, and are constructed after October 1, 1973. The provisions apply to nuclear power, although regulation of nuclear radiation is preempted by the federal government. Only electric utilities as defined by the PPSA may apply for certification. The process includes mandatory land use and certification hearings by an administrative law judge, a Determination of Need by the Public Service Commission (PSC), with ultimate approval/denial authority vested in the Siting Board, which consists of the Governor and Cabinet. The DEP coordinates the process.

While the PPSA has proved an effective mechanism for the licensing of new generation, recommended changes for simplifying and expediting the review process, ensuring protection for the environment and maintaining public participation include:

- Simplifying and streamlining completeness and sufficiency procedures;
- Reducing mandatory hearings;
- Revising time limits;
- Clarifying applicability; and
- Clarifying the statutes defining the authority of the Siting Board to review local government determinations on land use consistency to ensure the successful development of projects critical to the State's welfare.

Improving the efficiency of the PPSA and clarifying provisions will expedite power plant licensing, ensure quicker development of diverse generation infrastructure and enhance reliability.

Recommendation #2

Streamline and expedite the siting and permitting of electric transmission and distribution resources by revising the provisions of the Florida Electrical Transmission Line Siting Act. By 2006, reduce the average processing time for new transmission resources by three months while maintaining opportunities for public input and protecting Florida's environment. (Department of Environmental Protection, Siting Board)

Similar to the PPSA, the Transmission Line Siting Act (TLSA) is a centralized, coordinated licensing process encompassing permitting, land use and zoning, and proprietary interests of all state, regional, and local agencies in the jurisdiction of which a transmission line is proposed for location. The TLSA provides for a single certification (license) for transmission lines subject to the TLSA. Transmission lines subject to the TLSA are those which are 230 kilovolts or greater, 15 miles or more in length and cross a county line. The process includes a mandatory hearing by an administrative law judge, a Determination of Need by the PSC, with ultimate approval/ denial authority vested in the Siting Board. The DEP coordinates the process.

Recommended changes for simplifying the TLSA , expediting the review process, improving efficiency and enhancing reliability, while protecting the environment and maintaining public participation include:

- Simplifying and streamlining completeness and sufficiency procedures;
- Reducing mandatory hearings;
- Revising time limits;
- Clarifying who may be an applicant; and
- Clarifying comprehensive planning and zoning issues.

Improving the efficiency of the TLSA and clarifying provisions will expedite transmission line licensing and ensure quicker development of reliable transmission infrastructure.

Recommendation #3

Promote fuel diversity, fuel supply reliability and energy security.

- Provide the Public Service Commission with authority to ensure fuel diversity, fuel supply reliability and energy security as priority considerations when evaluating the state's energy needs. (Public Service Commission; Florida Legislature)

- Study transmission grid reliability to examine the efficiency and reliability of power transfer and emergency contingency conditions. (Public Service Commission)

- Study subterranean placement of distribution lines and the hardening of infrastructure to address issues arising from the 2004 and 2005 hurricane seasons. Upon determination of need, the Legislature should provide the Public Service Commission statutory authority to establish standards to reduce the vulnerability of Florida's power distribution infrastructure to hurricanes. (Public Service Commission)

The Florida PSC is charged with ensuring the development of reliable electric system resources in a manner that is economically competitive and protective of consumers. While a diverse fuel base enhances system reliability and energy security, it is currently not a major factor in the PSC's decision making. Empowering the PSC to include fuel diversity, fuel supply reliability, and energy security as high priorities in its decision making processes will enable the development of a diverse infrastructure in the state.

Chapter 366, Florida Statutes, provides the PSC with the authority and mechanisms for ensuring the provision of adequate, reliable, reasonable cost electricity to consumers. The PSC should support an update of Chapter 366, Florida Statutes, to include fuel diversity and fuel supply reliability as criteria for the installation of new electric generating infrastructure.

Chapter 403.519, Florida Statues, provides the guidelines for a determination of need for an electric generating facility. Prior to building a facility, Rule 25-22.082, Florida Administrative Code, requires that an applicant apply for a determination of need. A clause should be added to Chapter 403.519, Florida Statutes, to ensure the PSC considers fuel diversity and fuel reliability as factors when determining the need for new generation.

With a growing economy, additional transmission capacity will likely become necessary. There also may be a need to improve the efficiency and reliability of transferring power within certain regions of the state. It is therefore recommended that the PSC conduct a study of transmission grid reliability and emergency contingency conditions. The utilities in the state are encouraged to provide assistance to the PSC in conducting the study.

Distribution lines are essential to the delivery of generated power to residential and commercial consumers. These lines are particularly vulnerable to disruption when impacted by a hurricane. The PSC should work with local and state officials to review the feasibility of subterranean placement of distribution lines and other infrastructure hardening issues.

Recommendation #4

Facilitate additional fuel delivery mechanisms in Florida for power generation. Expedite all State permits required for redundancies and increased capacity. (Department of Environmental Protection, Board of Trustees of the Internal Improvement Trust Fund)

The interruption in the supply of natural gas and petroleum resulting from Hurricane Katrina in 2005 left Florida in an extended state of emergency. Source refineries for petroleum and a pipeline delivering a major portion of Florida's natural gas supply were damaged and offline. Because of these major interruptions, Florida's utilities began implementing emergency procedures using back up fuels and urging consumers to reduce electricity consumption and conserve fuel.

Florida can limit interruptions to electric generation fuel supply by diversifying its sources of fuel. Two natural gas pipelines have been approved to deliver liquefied natural gas, and there is interest in establishing additional natural gas and petroleum pipelines. The DEP recommends the State continue to explore mechanisms for creating redundancy in fuel supply and fuel delivery.

Recommendation #5

Adopt updated interconnection standards to include all distributed generation technologies. (Public Service Commission)

Distributed generation refers to self-generated, modular electricity generators sited close to the customer load. Distributed generation technologies include wind, solar, biomass, fuel cells, gas microturbines, hydrogen, combined heat and power, and hybrid power systems. Distributed generation systems can be integrated with electricity provided from a utility, enabling utilities to defer or eliminate costly investments in transmission and distribution system upgrades, and provide customers with better quality, more reliable energy supplies.

PSC Rule 25-6.065, which references the Institute of Electrical and Electronics Engineers' standard IEEE 929, currently allows for streamlined standards for the interconnection of "small photovoltaic systems" of 10 kilowatts or less to the local power grid.

It is recommended that PSC Rule 25-6.065 be expanded to incorporate the updated national standard IEEE 1547, which considers uniform connection standards associated with all distributed generation technologies including larger systems greater than 10 kilowatts. Uniform connection standards will minimize barriers to distributed generation interconnection.

Recommendation #6

By September 1, 2006, establish an energy council of diverse stakeholders to provide policy advice and counsel to the Governor, Speaker of the House and Senate President. (Florida Legislature)

Energy is essential to the economic health of Florida. With the increase in population and demand for energy, and the threat of supply disruptions it is imperative that policy makers are provided with objective recommendations on current and projected energy issues. The council should be comprised of a diverse group of stakeholders, including utility providers, researchers, fuel suppliers, technology manufacturers, environmental interests and others, and should advise the State on ideas and solutions to address energy needs and concerns.

Conservation Recommendations

Recommendation #7

Expedite State performance contracting with Energy Service Companies. By 2006, State government should generate energy savings of over $1 million or 3.5 million kilowatt hours annually as a result of these contracts. (Department of Management Services, Department of Financial Services, State Agencies)

In 1997, the Department of Corrections executed an energy savings contract with Florida Power and Light involving 16 institutions covering 4.6 million square feet. Over four years, the energy service contract has achieved a savings in electric, water and operating costs of more than $1.3 million annually.

In 2003, at the direction of Governor Bush, the State began to initiate contracts with Energy Service Companies (ESCOs) to evaluate State facilities for energy efficiency improvements. The ESCOs operate under performance contracts, receiving payment based on the savings generated for the State.

The DEP recommends the Department of Financial Services, Department of Management Services and State agencies expedite contract negotiations with ESCOs and implement performance contracts to allow earlier construction and energy savings.

Recommendation #8

Promote awareness of energy conservation and alternative energy technologies.

- Incorporate energy conservation, efficiency and alternative energy technologies into curriculum at K-12 public schools and universities. (Department of Environmental Protection)
- Encourage architects, engineers, building contractors, developers and community planners to practice sustainable, energy-efficient design and green building strategies. (Department of Environmental Protection)
- Encourage manufacturers and independent power providers to take advantage of waste energy and use cogeneration technologies. (Department of Environmental Protection)

Recommendation #9

Use discretionary enforcement authority to allow approved alternative energy projects that provide a greater public benefit in lieu of civil monetary penalties. (Department of Environmental Protection)

Fostering energy conservation and efficiency begins with awareness. Through a network of existing partners, the State is building understanding about energy conservation, energy efficiency and alterative and renewable energy technologies for the home and workplace.

As advancements in clean energy technologies and energy efficient practices evolve, continued outreach and education is needed to make these opportunities mainstream. For example, Combined Heat and Power (CHP) is an efficient, clean, and reliable approach to generating power and thermal energy from a single fuel source. By better understanding the potential benefit of CHP, Florida's industrial sector can increase operational efficiency and decrease energy costs, while reducing emissions of greenhouse gases.

Other education efforts can have the ability to reach a variety of audiences including the online Utility Report Card for public schools energy officials, training for home builders on energy efficient and hurricane resistant construction practices, case studies on biogas generation for dairy farmers, and energy-related classroom activities for elementary school students.

The DEP is also currently pursuing nearly $380,000 in funding from the State Technologies Advancement Collaborative to lead a five-state initiative to promote ENERGY STAR™ benchmarking tools and technical assistance for K-12 public schools and local governments throughout the Southeast United States. This outreach project builds on Florida's existing SunSmart Schools Program, which has installed 29 solar electric systems in public schools throughout the state. The program combines State funding with private partnerships to generate clean energy used by the school and create a hands-on science project for students.

The DEP has the authority to collect cash penalties for violations of environmental laws. The agency currently manages an enforcement program called "Pollution Prevention Projects in Enforcement" that allows DEP to settle enforcement actions by requiring the completion of an environmental project in lieu of civil penalties. The program requires the company to invest 1.5 times the value of the civil penalty in the pollution prevention project.

Where less serious violations occur, the DEP recommends allowing options for implementing alternative energy or energy efficiency projects in lieu of cash penalties, where the project provides a greater environmental and community benefit than civil enforcement. The DEP would recommend appropriate projects on a case by case basis.

Recommendation #10

Require all new State government building construction to meet the U.S. Green Building Council's Leadership in Environmental Design standards. Encourage local governments and community developers to adopt high performance green building practices. (Department of Management Services, Department of Community Affairs)

State government is leading by example with a strategic goal to reduce energy consumption by 25 percent below 2002 levels at all State government facilities by 2007.

To improve building efficiencies within State government and achieve the 2007 energy reduction goals, all new State buildings should meet the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) standards. Developed by all sectors of the building industry, the LEED program is a voluntary, consensus-based national standard for developing high-performance, sustainable buildings.

To improve building efficiencies outside of State government, the Department of Community Affairs should encourage local governments and community developers to adopt the Florida Green Building Coalition's recommendations for municipalities, such as expediting residential building permits for homes built to high energy efficient standards. Utilities should be encouraged to offer rebates for new and renovated ENERGY STAR™ certified homes.

Economic Incentive Recommendations

Recommendation #11

Provide grant funding for research and demonstration projects associated with the development and implementation of renewable energy systems. Expand solar, hydrogen, biomass, wind, ocean current and other emerging technologies. By 2007, the grant portfolio should realize an aggregate return on investment greater than two to one. (Department of Environmental Protection)

The DEP is currently administering approximately $5 million in grant funding to advance renewable and emerging alternative energy technologies for electricity generation. Additional funding is needed to build on these efforts and continue vital research and demonstration of these next generation technologies.

Industry and the State's universities contain the experience and expertise necessary to improve alternative energy technologies. By sponsoring further research, development and demonstration projects, the State can continue fostering these technologies in the marketplace and spurring economic investment in Florida.

Recommendation #12

Identify alternative energy production and distribution industries as Qualified Target Industries. (Enterprise Florida, Governor's Office of Tourism, Trade and Economic Development, Department of Revenue)

Administered through the Governor's Office of Tourism, Trade, and Economic Development, Qualified Target Industries (QTI) incentives are available to companies that create high wage jobs in targeted industries. Economic incentives include refunds on insurance premiums and corporate income, intangible personal property, sales and ad valorem taxes.

QTI designation will authorize tax refunds for companies that invest in Florida's alternative energy production and distribution industries.

Recommendation #13

Provide consumer and commercial rebates to assist with initial cost of photovoltaic and solar thermal technology installations on residential and commercial buildings. By 2007, achieve at least 725 new solar installations in Florida. (Department of Environmental Protection)

Photovoltaic systems convert sunlight into electrical current but have high initial costs associated with installation. Similarly, while solar water heaters are considered cost effective, the thermal technology has a higher initial cost than traditional fossil-fuel based water heaters. When installed, however, solar water heaters can provide as much as 80 percent of the hot water demand of the typical Florida residence.

By reducing installation costs, a rebate program would create an incentive for utilizing photovoltaic systems and solar water heaters both residentially and commercially. Promoting these technologies would also provide an economic benefit for Florida's native solar industry, reduce consumer energy costs and reduce grid demand at peak times. In addition, photovoltaic systems of two kilowatts or higher power output can supplement grid supplied power.

Subject to appropriation, the DEP will establish a solar rebate program for solar thermal and solar photovoltaic technologies, providing:

- Rebates per installed watt for photovoltaic systems in residential, commercial, public and non-profit applications.
- Rebates for the installation of solar thermal systems, excluding swimming pool heaters. A fixed rebate will be offered for residential applications. For commercial, public and non-profit applications, the rebate will be on a system performance basis.

Recommendation #14

Provide consumer rebates for purchases of energy efficient ENERGY STAR™ appliances. By 2007, achieve an energy savings of 20 million kilowatt hours per year. (Department of Environmental Protection)

ENERGY STAR™ is a government-backed program that promotes the use of industrial and household energy efficient appliances. According to ENERGY STAR™, the national average for household expense for energy bills is $1,500 a year. With ENERGY STAR™ products and home improvements, energy savings can reach 30 percent or more than $450 per year.

Subject to appropriation, the DEP will establish a rebate and incentive program for Florida residents on the purchase of eligible ENERGY STAR™ appliances. Specified funds will be directed toward an incentive program to support residents in low income communities.

Under the 2005 Federal Energy Policy Act, additional federal financial incentives may be available to consumers that purchase ENERGY STAR™ appliances.

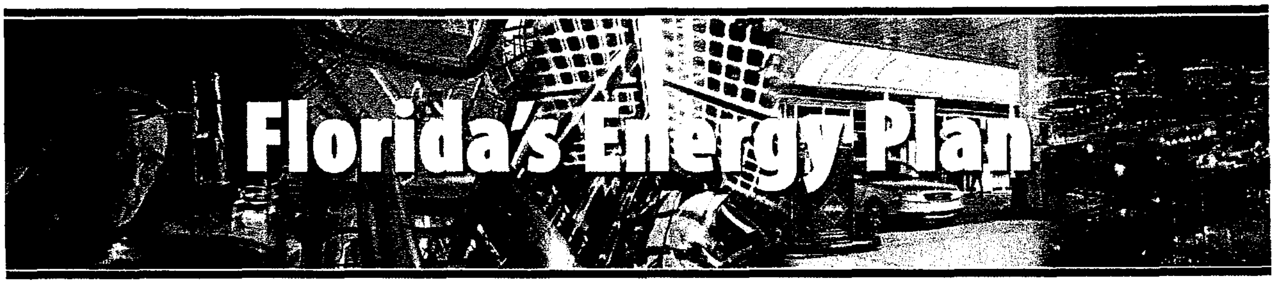
Recommendation #15

Provide sales and corporate tax incentives for the [illegible] purchase and use of fuel cells for supplemental and backup power. Grow demand for hydrogen energy technologies by 100 percent over the next two years. (Department of Environmental Protection, Department of Revenue)

Hydrogen fuel cells are unique in terms of the variety of their potential applications, providing energy for systems from laptop computers to utility power stations. Offering several benefits over conventional combustion-based technologies, fuel cells are currently used in many power plants and generators and are virtually pollution free.

Additional investments in the fuel cell industry will continue the advancement of fuel cells for use in backup and supplemental electricity generation and lead to lower cost, higher efficiency products.

Sales and corporate income tax incentives will spur investment in the fuel cell industry promoting advancements and improvements in the technology. Tax incentives will encourage Florida businesses to invest in alternative energy for backup and supplemental power.



V. Recommendations for Transportation Fuels

Diversification Recommendations

Recommendation #1:

Facilitate additional and diverse petroleum supply and distribution mechanisms into and within Florida. Expedite all State permits required for redundancies and increased capacity. (Department of Environmental Protection, Board of Trustees of the Internal Improvement Trust Fund)

Florida imports 98 percent of its transportation fuel into three major ports. Although Florida did not experience extended closures at its major ports during the 2004 and 2005 hurricane seasons, the state experienced long lines and limited fuel supplies at retail stations following each storm. In addition, shortages were experienced by emergency responders and electricity generating facilities. The interruption in the supply of petroleum resulting from Hurricane Katrina in 2005 left Florida in an extended state of emergency.

Several factors can impact Florida's fuel supply and the 2004 and 2005 hurricane seasons caused several of them to surface. Reoccurring problems in the current fuel supply and distribution networks can be linked to the following:

• Storage capacity limitations in the Panhandle: In 2004, Hurricane Ivan severely damaged a Transmontaigne fuel terminal in Pensacola. The facility is still closed.

• Seaside re-supply disruptions: Since Florida is dependant upon re-supply via sea, long term port closures impact fuel availability.

• Electricity outages at supply terminals and retail stations: Widespread electricity outages plagued fuel distribution in Florida during the 2004 and 2005 hurricane seasons.

• Inadequate ground transportation of fuel: The 2004 and 2005 hurricane seasons proved that pre and post-storm activities caused demand for fuel to exceed supply at retail stations. A lack of fuel delivery trucks resulted in rapid draw down and retail facility outages.

To meet Florida's increasing demand for fuel, the DEP recommends facilitating the expansion of fuel infrastructure, exploring the feasibility of developing petroleum pipelines to create redundancies in fuel delivery mechanisms and increasing petroleum storage capacity at Florida's ports.

Recommendation #2

Encourage fueling stations to cooperatively adopt a system modeled after the Florida WARN System to facilitate the relocation and use of generators to reestablish service. By June 1, 2006, register 10 percent of Florida's fueling stations as participants in the network. Double participation by June 1, 2007. (Department of Environmental Protection, Florida Petroleum Industry)

During the 2004 and 2005 hurricane seasons some fueling stations used generators to provide electric power to the station and the fueling pumps. This power enabled the stations to quickly return to operation and provide fuel. Fuel stations without generators were reliant on the restoration of local power.

Utilizing a system similar to the Florida WARN (Wastewater/water Agency Response Network) System will facilitate the installation of temporary power to return fuel to hurricane-affected communities without mandating the use of generators at gas stations or requiring government intervention in the market place. A web-based system would enable private entities to share resources. Generators in unaffected areas can be moved to impacted areas by private parties.

Conservation Recommendations

Recommendation #3

Foster state-local partnerships to encourage well-designed transportation and transit systems between established communities and within new community development. (Department of Environmental Protection, Department of Community Affairs, Department of Transportation)

Smart growth is development that serves the economy, community and the environment. The features that distinguish smart growth in a community vary from place to place. In general, sustainable growth invests time, attention, and resources in restoring community and vitality to center cities and older suburbs. This growth tends to be more town-centered, is transit and pedestrian oriented, and has a greater mix of housing, commercial and retail uses. It also preserves open space and many other environmental amenities.

The DEP recommends exploring the potential for partnerships with local planning boards that foster smart growth, with emphasis on improved transportation and transit systems. The partnerships are not intended to create regulations or process but rather to facilitate information sharing about emerging technologies and existing infrastructure that reduce a community's dependence on fossil fuels.

The State should also facilitate continued discussions between the Florida Department of Transportation, local governments and the CSX Corporation to utilize existing freight tracks for commuter rail service in Central Florida. Mass transit projects like this aid in reducing congestion on Florida roads and provide a viable transportation alternative for commuters.

Recommendation #4

Raise public awareness for alternative fuel vehicles through public programs. Encourage public entities, including school districts and local governments, to use biofuels in fleets. (Department of Environmental Protection)

Numerous alternative fuel vehicle options exist, including hybrid electric, biodiesel, ethanol blends, electric, compressed natural gas, liquefied natural gas, propane and hydrogen.

Increased awareness about vehicle options will help foster demand for these alternative fuels and vehicles. Improved market penetration will help economies of scale. Government can lead by example and create market demand to help drive unit costs down.

Economic Incentives

Recommendation #5

Provide grant funding for applied research and demonstration projects associated with the development and implementation of alternative fuel vehicles and other emerging technologies. By 2007, the grant portfolio should realize an aggregate return on investment greater than two to one. (Department of Environmental Protection)

The DEP is currently administering approximately $7 million in grant funding to support transportation-related research, development and demonstrations in alternative fuels and advanced energy technologies in Florida. Additional funding is needed to build on these efforts and continue vital research and demonstration of these next generation technologies.

Industry and the State's universities contain the experience and expertise necessary to improve alternative fuels and energy technologies. By sponsoring further research and demonstration projects, the State can continue to bring these technologies closer to market.

Recommendation #6

Provide sales and corporate income tax credits for hydrogen vehicles and fueling infrastructure. By 2007, increase demand for mobile hydrogen technologies by 50 percent. (Department of Environmental Protection, Department of Revenue)

Worldwide, energy companies, automakers and petroleum companies are investing more than $2 billion annually to expand the hydrogen technology industry. Nationally, President George W. Bush proposed a $1.7 billion, five-year investment to develop hydrogen-powered fuel cells, hydrogen infrastructure and advanced automotive technologies.

Since July 2003, the State has invested $3.8 million for hydrogen research, development and demonstration and has experienced an overall return on investment of nearly four to one. Continued investment from the State will stimulate Florida's hydrogen economy, create incentives for corporate investment, diversify the economy and create high-wage jobs.

Recommendation #7

Provide corporate sales and income tax incentives to improve production, develop distribution infrastructure and increase availability of clean fuels, including biodiesel and ethanol. (Department of Environmental Protection, Department of Revenue)

While biodiesel production capacity in Florida is growing, a large percentage of product is railed out-of-state.

Bulk storage capacity for biodiesel currently exists at the Port of Tampa and Port Everglades, although there are no existing plans for additional storage elsewhere in the state. To reduce costs and increase demand within the state, the DEP recommends expanding bulk storage at main petroleum terminals in Central and North Florida to allow fuel companies to blend biodiesel at the rack. By increasing availability and access, the state can enhance the market for biodiesel.

Fuel-grade ethanol production is growing in Florida and across the nation, although retail access to ethanol-blended fuel is limited. The DEP recommends using E85 (a blend of 85 percent ethanol and 15 percent gasoline) to fuel government fleets with flex-fuel vehicles, creating an immediate market for E85 and spurring private investment in infrastructure. The DEP also recommends exploring the potential for lower blends of ethanol, such as E10 (a blend of 10 percent ethanol with 90 percent gasoline), which may be viable for mainstream use without the need for flex-fuel vehicles.

Corporate sales and income tax credits will be offered to the production, storage and distribution of clean fuels. Investment from the State will stimulate investment in Florida, create incentives for corporate investment, diversify the economy and create high-wage jobs.

In addition to the economic incentives proposed by the State, the U.S. Department of Agriculture (USDA) has a comprehensive energy strategy to help farmers and ranchers deal with high energy costs. As part of its support for energy projects, the USDA awarded $1.2 million in Small Business Innovation Research grants to eight projects involving biomass fuels, byproducts, and power. In addition, the USDA's Rural Development program plans to maximize its use of approximately $1.4 billion in various business and electric loans and loan guarantees to help farmers, ranchers, and rural communities create renewable energy systems and businesses. This program provides guarantees up to eighty percent of a loan made by a commercial lender. The DEP recommends utilizing federal loans by Florida businesses to expand and enhance ethanol production in the state.

Gas Production Outlook: U.S. Onshore Mature Group

BCF/D	12-02	12-03	12-04	12-05	12-06
U.S. Dry Production	51.2	51.5	50.4	49.4	53.0
Onshore Total	37.9	39.1	39.9	41.2	43.7
Onshore Mature Group	22.6	23.5	23.7	24.4	26.3
Rockies/Other	15.3	15.5	16.1	16.8	17.4
Offshore GOM	13.3	12.4	10.6	8.2	9.4

May not sum to totals owing to rounding

Gas producers' unprecedented efforts to revitalize U.S. production have turned the corner. Despite the Onshore Mature Group's (MG) dramatic post-'02 rig count escalation, the region had little to show for its efforts outside a one-time rebound from price-depressed '02 levels — that is, until the second half of last year. By 12-05, the Onshore MG's Y/Y growth had reached ~0.7 BCF/D (~0.9 BCF/D excluding lingering effects of last year's hurricanes).

Barring the curtailment of gas-oriented drilling from further summer '06 price erosion, we see no slowdown in sight thanks to the upward momentum of the Group's drilling intensity and its support from the NYMEX forward price curve. Indeed, PIRA's *Vintage Models* foresee Onshore MG Y/Y growth of 1.5-2.0 BCF/D by 12-06, sending a powerful message to cynics who gave up on the region's upside potential some time ago. Elsewhere, growth underpinned by the Rockies is forecast to push total onshore production higher Y/Y by 2.5 BCF/D.

Until the current quarter, massive offshore GOM losses largely attributable to hurricanes Ivan, Katrina and Rita had been surpassing onshore production gains. But we anticipate that offshore GOM output will turn positive Y/Y in 2H06, even in the face of another active hurricane season. If so, U.S. dry gas production would top the year-earlier level by a staggering 3-4 BCF/D in 12-06.

Since producers are not known for making speculative pipeline investments, the bevy of supply-driven pipeline projects moving forward adds credibility to our production outlook. The unmistakable fact that producers as opposed to LNG importers anchor the vast majority of projects, which overlay the Onshore MG, calls attention to producers' conviction that more supply-area pipeline capacity will be needed.

At the end of the day, U.S. gas demand will be hard-pressed to keep pace with such indigenous production growth. Ultimately, therefore, PIRA foresees the NYMEX "strip" giving domestic producers a more cautious price signal to bring the market into better balance.

PIRA employs multiple procedures to forecast near-term U.S. gas production. For Majors and Independent producers, we use drilling/output models that separately forecast gas output of each group. For the Onshore Mature Group, we use the *Vintage Models* discussed in this report that reflect correlations between rig counts and new gas together with decline rates of older wells.

EXHIBIT
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Dry Gas Production (BCF/D)	12-02	12-03	12-04	12-05	12-06
Onshore Mature Group	22.58	23.49	23.66	24.38	26.28
Gulf Coast Area	10.39	10.75	10.66	10.91	11.63
Midcontinent	8.10	8.64	8.90	9.51	10.42
Permian Basin	4.10	4.10	4.10	3.96	4.23

May not sum to totals owing to rounding.

OVERVIEW

Vintage Model Area: Following substantial growth since '02, conventional wisdom would argue that onshore Mature Group gas producers are in danger of becoming victims of their own success, given the dynamics of the proverbial gas "production treadmill" (a.k.a. the *increasing* supply from new wells needed to replace annual declines from older wells). Yet, current year-to-date results suggest just the opposite. Namely, the region's current year output growth appears on track to surpass all prior annual gains since the '02 trough.

Table 1: Vintage Model Drilling & Production

Dec.	Drill Inten.	New Wells	Decl. Rate	New Gas	Other Gas	Total Prod.
	Rigs	Thous.	%		BCFD	
02	428	6.9	41	4.05	13.07	17.12
03	500	8.3	23	4.87	13.12	18.00
04	606	10.2	26	4.99	13.27	18.26
05	697	11.2	28	5.89	13.18	19.07
06	794	12.1	26	6.43	14.16	20.59

In Vintage Model Areas, drilling intensity almost breached the 700 mark in 12-05, surpassing the prior pace by 15%. Now in its fourth year and on track to post at least comparable growth in '06, the ongoing drilling boom has become truly imposing in both strength and duration. Model Area new gas wells are also on track to reach yet another all-time high.

Domestic producers have left none of the onshore MG's sub-regions behind. While new plays are enjoying a flurry of activity, traditional basins are also benefiting from a second wind. Indeed, the acceleration in drilling activity at work since 2003 has been observed in all Model Areas.

Those "sub-regions" have been put together largely on the basis of homogeneous gas supply and location. They include the Texas Gulf Coast (railroad districts 1-4, and 6), north and south Louisiana, the Barnett Shale Area (RRD 5, 7B, 9), Oklahoma and RRD 10 in the Mid-Continent and RRD 7C in the Permian Basin[1].

Table 2: Vintage Model Area Drilling Efficiency

Dec.	02	03	04	05	06
MMCFD/Well	0.59	0.59	0.49	0.53	0.53
Wells/Rig/Yr	16.0	16.6	16.9	16.1	15.3
MMCFD/Rig	9.5	9.8	8.2	8.5	8.1

In '05, overall Model Area drilling efficiency increased in terms of new gas delivered per active rig. Although the number of new wells per rig declined (16.9 to 16.1), that reduction was more than offset by improved first-year well productivity (490 to 530 MCF/D per well). Rig efficiency gains stemmed from the dominance of incremental drilling in high well productivity sub-regions (e.g. Texas Gulf, N. Louisiana) and little or no growth in low well productivity sub-regions (e.g. Oklahoma, RRD 7).

The combination of improved rig efficiency and more intensive drilling intensity pushed "new gas" in 12-05 up to 5.9 BCF/D, a stunning 0.9 BCF/D jump from the year-earlier level. However, "other gas" (largely from older wells) stagnated at 13.2-13.3 BCF/D, reflecting only modest Y/Y baseline expansion (18.0 to 18.3 BCF/D) and a faster decline rate (26 to 28%).

[1] Please refer to the Glossary of Terms on page 12 that defines "new gas" and other terms used in our vintage model analysis and map on page 11 that locates each sub-region.

For 2006, the Model Area's performance is shaping up to be a dramatically different story. We foresee "new gas" growth to reach only ~0.5 BCF/D but "other gas" expand by 1.0 BCF/D, causing total Model Area supply to jump 1.5 BCF/D. Slower "new gas" growth stems from a further contraction in the annual number of wells per rig without offsetting growth of output per well. Thus, annual rig efficiency falls from 8.5 to 8.1 MMCF/D per rig.

"Other gas" growth in '06 of 1.0 BCF/D provides the critical underpinning for robust overall output expansion. From 12-05 to 12-06, "other gas" will be the beneficiary of both higher drilling intensity and a *slower* annual decline rate (28 to 26%). The slower decline rate stems from the anomaly of depressed Louisiana output in 12-05 caused by the lingering effects of last year's hurricanes.

Other Mature Group Areas: In some sub-regions, available data are inadequate to capture the structural dynamics behind gas production trends (Alabama/Florida and Mississippi in the Gulf Coast, as well as Arkansas and Kansas in the Midcontinent). In S.E. New Mexico and RRD 8/8A in the Permian Basin gas-oriented drilling efficiency cannot be measured realistically owing to the dominance of associated gas.

Table 3: Mature Group Outside Model Areas (BCFD)

Prod. Dec.	Gulf	Midcon	Permian	Total
02	.66	1.53	3.27	5.46
03	.76	1.48	3.25	5.49
04	.74	1.48	3.18	5.40
05	.80	1.46	3.05	5.31
06	.81	1.55	3.33	5.71

In '06, we expect total production in these regions to expand by 0.4 BCF/D. Standouts for expected growth within this group are Arkansas (the Arkoma Basin's unconventional shale play) and Southeastern New Mexico (sub-normal 12-05 output).

GULF COAST AREA

Texas Gulf Area: Albeit in a less spectacular way than some other regions, the Texas onshore GOM has shown a major revival in drilling intensity over the past several years. In 12-05, 12-month drilling intensity (261) surpassed 12-04 (208) and 12-03 (192) by a 25% and 36%, respectively[2].

However, high "other gas" decline rates have speeded the region's production "treadmill," curbing the impact of new gas on total production growth. In addition, the systematic fall in rig efficiency have mitigated the positive impact of more intensive gas-oriented drilling. Those declines of course can be anticipated when rising drilling intensity reduces prospect quality.

Table 4: Texas Gulf Area (RRD 1-4, 6)

DEC.	02	03	04	05	06
BCFD Sum	6.89	7.11	6.94	7.12	7.39
% Decl. Yr.	32	29	33	35	34
BCFD New	1.81	2.23	2.15	2.62	2.69
Dril. Inten.	173	192	208	261	269
MMCFD/Rig	10.4	11.6	10.4	10.0	10.0
Wells/Rig/Yr	14	15	16	16	16
MCFD/Well	772	749	658	628	625

In '06, output is projected to reach ~7.4 BCF/D, a Y/Y increase of ~250 MMCF/D, or slightly more than last year's growth. The forecast acceleration can be attributed to continued aggressive drilling expansion with 12-06 drilling intensity reaching only 269 rigs, coupled with a rising baseline and fairly stable decline rates.

Southern Louisiana: Thanks to record-high gas prices, ready access to pipelines and a strong oil and gas industry culture, Louisiana has become, once again, an aggressively targeted E&P area. Within the State, however, major differences are evident in recent trends as well as in the outlook for gas production.

Output in southern Louisiana (slightly over one-half of the State's total) has been generally on the decline over the past five years. Until '05, drilling intensity as well as gas rig efficiency had remained fairly stable. In 12-05, however, the positive impact on

[2] Please refer to the tables on pages 8-9 for additional details on Vintage Model Area drilling and production from 12-02.

production of expanded drilling intensity was undermined by artificially high decline rates caused by earlier hurricane activity. Although a drilling slowdown seems in the making for the current year, overall gas supply in 12-06 should easily top the 12-05 level as output "normalizes" from those hurricane-distorted year-earlier levels.

Table 5: Southern Louisiana					
DEC.	02	03	04	05	06
BCFD Sum	1.98	1.95	1.82	1.63	1.80
% Decl. Yr.	34	28	31	40	20
BCFD New	.48	.52	.47	.53	.50
Dril. Inten.	44	42	43	51	47
MMCFD/Rig	10.9	12.4	10.9	10.5	10.5
Wells/Rig/Yr	6	7	8	7	7
MMCFD/Well	1.86	1.79	1.44	1.50	1.50

Northern Louisiana: In sharp contrast to the southern part of the State, this area has achieved consistent growth over the past three years. Here, more intensive drilling has not overtly influenced rig efficiency. With current rig counts leading their 12-month moving averages, the region's drilling intensity is set to escalate thanks to prospects in the expanded Cotton Valley play and the prolific Vernon field areas.

Table 6: Northern Louisiana					
DEC.	02	03	04	05	06
BCFD Sum	0.86	0.93	1.15	1.36	1.63
% Decl. Yr.	29	26	30	30	27
BCFD New	.22	.30	.50	.55	.65
Dril. Inten.	23	26	36	46	53
MMCFD/Rig	9.9	11.6	13.8	12.0	12.2
Wells/Rig/Yr	15	16	18	17	17
MCFD/Well	677	731	763	706	718

Moreover, output "normalization" from hurricane-distorted 12-05 levels should further boost current year growth, pushing overall supply up to ~1.60 BCF/D, up almost 0.3 BCF/D Y/Y.

Gulf Coast Outside Model Areas: In **Alabama** production has been remarkably stable of late owing to the counter-balancing impacts of modestly rising coalbed methane (CBM) from Black Warrior Basin and declining conventional gas output. CBM accounts for about 70% of the State's total production and should continue to expand given rising proven reserves. Although the opposite is true for conventional gas, future declines will reflect a baseline only slightly above 0.1 BCF/D. Dry gas output in **Florida** is only ~5 MMCF/D.

Table 7: Gulf Coast Outside Model Areas (BCF/D)					
DEC.	02	03	04	05	06
Sum	.66	.76	.74	.80	.81
Alabama/Fla.	.38	.43	.40	.40	.41
Miss.	.28	.33	.34	.40	.40

In recent years, **Mississippi** dry gas production has grown steadily. In 2005, output reached its highest annual average (386 MMCF/D) since the early 1980s and topped the prior year (361) by a comfortable margin. However, so far in 2006 the State's rig counts have fallen from year-earlier highs making sustained growth over the near-term problematic.

MIDCONTINENT

Barnett Shale Area: Located in northern Texas (RRD 5, 7B and 9), the Barnett Shale Area is the principal driver of production growth in both the State of Texas and the onshore MG as a whole. In contrast with most other plays, this expansion is being achieved through more intensive drilling without a major offset from reduced rig efficiency.

The quasi-constant flow of corporate announcements coming from the region confirms the sustainability of this upward trend. *And the numerous planned pipeline additions surrounding this play bolster our belief in the upside potential, too.* Pipeline capacity additions on the drawing board are rapidly becoming almost too many to list.

More than 100 companies are active in the Barnett Shale area. Devon, the largest player, has ~2,200 wells producing ~0.6 BCF/D. The company completed ~210 wells in 2005, of which ~150 were horizontal. Besides the 280 new wells planned for

2006, Devon plans to drill another 800 wells within five years in acreage recently acquired from Chief Oil and Gas. Other major players with active development plans include XTO Energy, ConocoPhillips, EnCana, EOG and Chesapeake. Such intense competition will play an important role behind the area's future growth.

Table 8: Barnett Shale Area (TX RRD 5, 7b, 9)					
DEC.	02	03	04	05	06
BCFD Sum	1.74	2.14	2.16	2.63	3.17
% Decl. Yr.	25	22	34	25	32
BCFD New	.61	.78	.75	1.01	1.38
Dril. Inten.	68	82	100	106	184
MMCFD/Rig	8.9	9.6	7.5	9.5	7.5
Wells/Rig/Yr	21	21	17	17	14
MCFD/Well	425	464	443	559	536

Improving technology and geological knowledge keep pushing the Shale's potential higher, but not all acreage holds equal potential. In 2005, ~60% of the Shale's production came out of District 9. The most actively drilled area is the Newark East field, listed as the largest in Texas by the *American Association of Petroleum Geologists*, and located across RRD 5's Tarrant and RRD 9's Denton counties. Tarrant County was producing ~0.3 BCF/D by end-2005, with neighboring Johnson County becoming the next "sweet spot" in the play.

Outside of these "core areas," important unknowns remain with respect to where the gas window ends in relation to future recovery factors and decline rates. Yet, large players are accelerating drilling intensity in part to hold their leases and increase their acreage. In such an intensely competitive environment, PIRA foresees new well startups in the Area soaring from ~1,800 in '05 to 2,400 in the current year, contributing to Y/Y overall production growth of ~0.5 BCF/D by 12-06. Alternatively, more stable drilling efficiency would translate into even higher production.

Oklahoma: In 2006, Oklahoma rig counts and gas production are on an upswing. The EIA's new Form-914 survey indicates that production was up Y/Y by 4% in April, a visible improvement over relatively stagnant output during the prior year. May '06 rig counts were up to a record post-90s high of 165, an 11% Y/Y gain.

Table 9: Oklahoma					
DEC.	02	03	04	05	06
BCFD Sum	4.03	4.14	4.34	4.36	4.52
% Decl. Yr.	22	15	13	16	14
BCFD New	.72	.73	.72	.70	.76
Dril. Inten.	90	116	153	150	159
MMCFD/Rig	8.1	6.3	4.7	4.6	4.8
Wells/Rig/Yr	18	16	17	15	15
MCFD/Well	446	386	276	310	320

Although still in their infancy, the Woodford Shale and Caney plays on the Oklahoma (western) side of the Arkoma Basin have become a focus of attention for several producers. Similarities to Barnett Shale are partly responsible. Newfield has launched a Woodford Shale horizontal drilling program with some suggesting that output could reach 0.2 BCF/D by 2008. Devon also is getting active in the area.

RRD 10: During the past two years, RRD 10 production has trended upward from 0.9 BCF/D to slightly over 1.0 BCF/D by 12-05. From 2H05 into early '06, the area's production appears to have reached a plateau, but its drilling began a second round of escalation in late '05 leading to a May '06 monthly rig count of 67. Given this drilling resurgence, we foresee the district's gas output reaching 1.2 BCF/D in 12-06.

Table 10: RRD 10					
DEC.	02	03	04	05	06
BCFD Sum	.80	.87	.92	1.06	1.18
% Decl. Yr.	19	12	18	18	19
BCFD New	.07	.17	.21	.31	.32
Dril. Inten.	13	22	40	57	65
MMCFD/Rig	5.7	7.7	5.2	5.4	5.0
Wells/Rig/Yr	23	20	16	14	14
MCFD/Well	248	395	327	386	357

A particularly active area within the District has been the Granite Wash field, with wells reaching depths of 11,000 to 14,000 feet. Owing to the depths and complexity of zones being drilled, this play needed the higher gas price thresholds of recent years to become viably economic despite relatively high initial production rates.

Midcontinent Outside Model Areas: The two states included in this subdivision could not be more contradictory. In **Kansas**, production remains on a long-term downtrend largely reflecting the maturity of Hugoton Gas Area that extends into Oklahoma and Texas. In 2004, the Area produced ~0.9 BCF/D, down from ~1.1 BCF/D only two years earlier. Nevertheless, declines have moderated over the past year or so.

Table 11: Midcontinent Outside Model Areas

DEC.	02	03	04	05	06
Sum	1.53	1.48	1.48	1.46	1.55
Kansas	1.08	1.00	0.94	0.93	0.93
Arkansas	0.45	0.48	0.53	0.53	0.62

At the other extreme, **Arkansas** gas rigs have leaped from under 5 to over 20 within the past year and further escalation is in the making. The impetus in this case is the Fayetteville Shale play on the Arkansas (eastern) side of the Arkoma Basin with key companies that include Southwestern Energy, Chesapeake, and Shell.

At this juncture, Southwestern Energy looks to be in the lead position to expand gas output with a massive leasehold position of 860,000 acres. Chesapeake holds the largest leasehold position (1.1 million acres) but has just started E&P activities in the area.

In May, the Arkansas Oil and Gas Commission projected that statewide gas output could jump from 0.5 to 0.8 BCF/D within two years assuming the aggressive development of Fayetteville Shale. Earlier this month, Arkansas adopted a new set of oil and gas leasing rules in response to the play's growing prominence.

Despite the Shale's similar geological characteristics to Barnett Shale, Southwestern has indicated that successful development requires significantly more than mimicking Barnett frac technology. PIRA will closely monitor this play given its upside potential and lead-time uncertainties.

PERMIAN BASIN

RRD 7C: This Permian Basin Texas District is somewhat unique in that its production is heavily gas-oriented. Three of its top four producing counties (including top-producing Crockett County), in fact, derive close to 90% of total gas output from gas wells. Four contiguous counties of Crockett, Sutton, Terrell, and Upton produce over 80% of the District's gas.

Table 12: RRD 7C

DEC.	02	03	04	05	06
BCFD Sum	.82	.85	.92	.91	.90
% Decl. Yr.	16	15	14	19	16
BCFD New	.14	.15	.19	.17	.14
Dril. Inten.	18	20	25	26	18
MMCFD/Rig	7.7	7.4	7.5	6.5	7.5
Wells/Rig/Yr	33	31	41	40	40
MCFD/Well	231	238	183	163	188

High gas prices have had a substantial impact on this area's highly gas-oriented E&P activities. However, production has not been commensurate with the aggressive drilling. Escalating "other gas" decline rates combined with falling rig productivity have limited output growth and should continue to dampen growth prospects in the months ahead.

After peaking ~0.9 BCF/D in '04, the District's gas production held steady into early '06. During the remainder of the year, output is projected to trend downward in response to weaker drilling intensity.

Permian Outside Model Areas: A high proportion of Permian Basin gas is associated with oil production; so high crude prices encourage oil drilling and its associated gas production. Oil's dominance is especially evident in RRD 8/8A and south eastern New Mexico.

RRD 8 and 8A show a precipitous decline in gas production over the past year due to an accounting inconsistency in District 8A regarding CO_2 injection. Our data, however, after adjustments for this inconsistency, reveal the Districts' gas production resilience in the 1.7-1.8 BCF/D area in recent years, with an almost even split between oil and gas wells. In this case, the oil *and* gas booms seem to be providing an equal dose of E&P incentives.

Table 13: Permian Basin Outside Model Areas

DEC.	02	03	04	05	06
Sum	3.27	3.25	3.18	3.05	3.33
RRD 8/8A	1.82	1.79	1.75	1.71	1.83
S.E. New Mex.	1.46	1.45	1.43	1.34	1.50

In **Southeastern New Mexico** gas production appears to have started '05 at almost 1.5 BCF/D before tailing off to 1.3-1.4 BCF/D by the fourth quarter. In 3Q05, however, the sub-region's rig counts began to move aggressively higher, starting from the mid-40s and reaching the mid-60s by May '06. Production also appears to have moved back into the 1.4-1.5 BCF/D range in 2Q06.

VINTAGE MODEL DRILLING & PRODUCTION									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	428	6,856	16.0	4.05	591	9.5	38	13.07	17.12
Jun-03	439	7,229	16.5	4.68	647	10.7	35	13.27	17.95
Dec-03	500	8,300	16.6	4.87	587	9.8	23	13.12	18.00
Jun-04	559	9,439	16.9	5.00	530	8.9	25	13.45	18.45
Dec-04	606	10,224	16.9	4.99	488	8.2	26	13.27	18.26
Jun-05	653	10,385	15.9	5.27	507	8.1	26	13.68	18.95
Dec-05	697	11,197	16.1	5.89	526	8.5	28	13.18	19.07
Jun-06	745	11,347	15.2	6.18	544	8.3	27	13.93	20.10
Dec-06	794	12,120	15.3	6.43	530	8.1	26	14.16	20.59

GULF COAST TEXAS (RRD 1-4, 6)									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	173	2,345	14	1.81	772	10.4	32	5.08	6.89
Jun-03	169	2,571	15	2.23	867	13.2	29	4.94	7.17
Dec-03	192	2,976	15	2.23	749	11.6	29	4.89	7.11
Jun-04	206	3,153	15	2.28	724	11.1	32	4.91	7.19
Dec-04	208	3,270	16	2.15	658	10.4	33	4.79	6.94
Jun-05	228	3,486	15	2.21	634	9.7	33	4.84	7.05
Dec-05	261	4,173	16	2.62	628	10.0	35	4.51	7.12
Jun-06	271	4,067	15	2.71	667	10.0	34	4.65	7.36
Dec-06	269	4,296	16	2.69	625	10.0	34	4.70	7.39

NORTHERN LOUISIANA									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	23	329	15	0.22	677	9.9	29	0.63	0.86
Jun-03	23	360	16	0.31	855	13.4	25	0.65	0.96
Dec-03	26	406	16	0.30	731	11.6	26	0.64	0.93
Jun-04	31	518	16	0.39	753	12.4	31	0.66	1.05
Dec-04	36	653	18	0.50	763	13.8	30	0.65	1.15
Jun-05	41	686	17	0.49	715	12.1	29	0.74	1.23
Dec-05	46	785	17	0.55	706	12.0	30	0.80	1.36
Jun-06	50	854	17	0.61	718	12.2	27	0.90	1.51
Dec-06	53	900	17	0.65	718	12.2	27	0.98	1.63

SOUTHERN LOUISIANA									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	44	258	6	0.48	1863	10.9	34	1.50	1.98
Jun-03	45	261	6	0.46	1752	10.2	25	1.64	2.10
Dec-03	42	293	7	0.52	1785	12.4	28	1.42	1.95
Jun-04	40	305	8	0.48	1577	11.9	29	1.49	1.98
Dec-04	43	328	8	0.47	1441	10.9	31	1.35	1.82
Jun-05	48	317	7	0.50	1574	10.4	29	1.40	1.90
Dec-05	51	356	7	0.53	1500	10.5	40	1.10	1.63
Jun-06	50	350	7	0.52	1500	10.5	30	1.33	1.85
Dec-06	47	332	7	0.50	1500	10.5	20	1.30	1.80

TX RRD 9, 7B & 5 (Inclusive of entire Barnett Shale production)									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	68	1,426	21	0.61	425	8.9	25	1.13	1.74
Jun-03	67	1,460	22	0.68	463	10.1	21	1.31	1.99
Dec-03	82	1,689	21	0.78	464	9.6	22	1.36	2.14
Jun-04	93	1,759	19	0.73	417	7.9	25	1.48	2.22
Dec-04	100	1,690	17	0.75	443	7.5	34	1.41	2.16
Jun-05	102	1,691	17	0.90	530	8.8	25	1.67	2.56
Dec-05	106	1,810	17	1.01	559	9.5	25	1.62	2.63
Jun-06	139	2,089	15	1.11	533	8.0	32	1.75	2.86
Dec-06	184	2,570	14	1.38	536	7.5	32	1.79	3.17

OKLAHOMA (Part of Midcontinent)									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	90	1,620	18	0.72	446	8.1	22	3.31	4.03
Jun-03	100	1,653	17	0.75	454	7.5	19	3.31	4.06
Dec-03	116	1,881	16	0.73	386	6.3	15	3.42	4.14
Jun-04	136	2,450	18	0.75	305	5.5	15	3.47	4.21
Dec-04	153	2,621	17	0.72	276	4.7	13	3.62	4.34
Jun-05	158	2,421	15	0.75	309	4.7	14	3.63	4.38
Dec-05	150	2,252	15	0.70	310	4.6	16	3.66	4.36
Jun-06	151	2,268	15	0.73	320	4.8	14	3.78	4.50
Dec-06	159	2,384	15	0.76	320	4.8	14	3.76	4.52

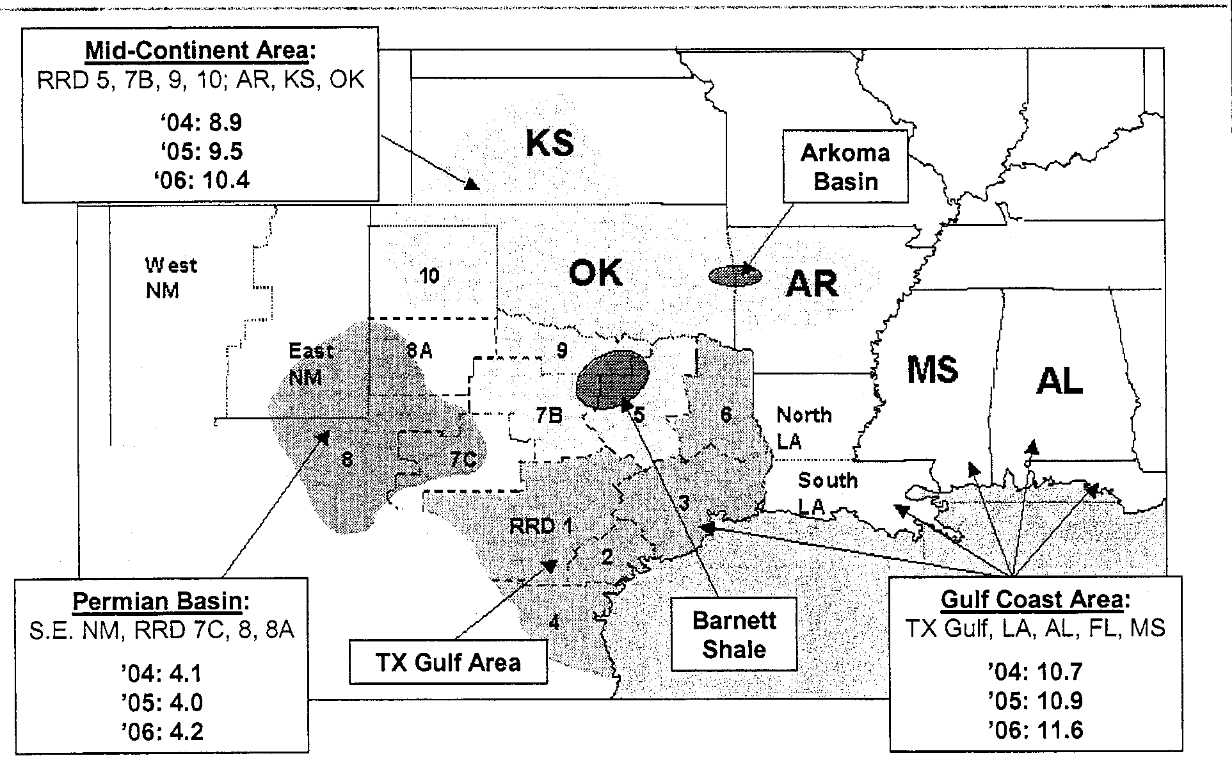
TX RRD 10 (Part of Mid-Continent)									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	13	292	23	0.07	248	5.7	19	0.73	0.80
Jun-03	16	354	21	0.12	331	7.1	16	0.72	0.84
Dec-03	22	423	20	0.17	395	7.7	12	0.70	0.87
Jun-04	30	508	17	0.21	410	6.9	14	0.73	0.93
Dec-04	40	634	16	0.21	327	5.2	18	0.71	0.92
Jun-05	50	680	14	0.23	342	4.7	25	0.70	0.93
Dec-05	57	800	14	0.31	386	5.4	18	0.75	1.06
Jun-06	61	856	14	0.33	386	5.4	17	0.77	1.10
Dec-06	65	905	14	0.32	357	5.0	19	0.86	1.18

TX RRD 7C (Part of Permian Basin)									
	Drilling Intensity	New Wells	Wells Per Rig	New Non-Asso. Gas BCF/D	MCF/D Per Well	MMCF/D Per Rig	Decline Rate %	Other Gas BCF/D	Total Prod. BCF/D
Dec-02	18	586	33	0.14	231	7.7	16	0.69	0.82
Jun-03	19	570	31	0.14	245	7.5	14	0.70	0.84
Dec-03	20	632	31	0.15	238	7.4	15	0.70	0.85
Jun-04	22	746	34	0.16	208	7.0	15	0.71	0.86
Dec-04	25	1,028	41	0.19	183	7.5	14	0.73	0.92
Jun-05	28	1,104	40	0.19	175	7.0	18	0.71	0.90
Dec-05	26	1,020	40	0.17	163	6.5	19	0.75	0.91
Jun-06	22	862	40	0.16	184	7.4	16	0.76	0.92
Dec-06	18	732	40	0.14	188	7.5	16	0.76	0.90

ONSHORE MATURE GROUP GAS RIGS					
12 Mo. Avg.	Sum	Texas Gulf Coast	North Louisiana	South Louisiana	Barnett Area
Dec-02	588	165	23	44	65
Dec-03	769	203	28	41	88
Dec-04	932	215	38	45	102
Dec-05	1044	269	48	52	121
By Month					
Jan-05	967	240	39	46	97
Feb-05	994	245	45	56	101
Mar-05	1009	261	49	57	111
Apr-05	1035	277	44	54	112
May-05	1020	282	44	47	112
Jun-05	1030	280	49	47	107
Jul-05	1046	280	48	52	112
Aug-05	1069	280	53	56	116
Sep-05	1070	283	53	53	114
Oct-05	1098	274	50	48	150
Nov-05	1094	266	50	52	161
Dec-05	1098	263	48	49	160
Jan-06	1090	248	54	47	166
Feb-06	1142	259	56	48	178
Mar-06	1123	261	55	46	184
Apr-06	1170	273	55	44	198
May-06	1197	276	57	44	201

12 Mo. Avg.	Midcon.	Permian	Oklahoma	TX RRD 10	TX RRD 7C
Dec-02	111	59	91	14	18
Dec-03	159	77	127	25	21
Dec-04	212	91	157	45	27
Dec-05	223	98	150	60	23
By Month					
Jan-05	218	88	149	60	30
Feb-05	218	89	154	59	28
Mar-05	211	89	149	55	26
Apr-05	219	92	152	58	27
May-05	215	92	148	58	22
Jun-05	225	90	148	62	22
Jul-05	225	98	146	62	24
Aug-05	228	104	154	57	21
Sep-05	223	114	146	61	23
Oct-05	232	109	151	62	21
Nov-05	230	106	149	63	18
Dec-05	234	109	150	65	20
Jan-06	231	112	149	63	20
Feb-06	246	107	163	62	23
Mar-06	242	95	158	62	21
Apr-06	248	111	160	64	17
May-06	255	114	165	67	18

Onshore Mature Group's End-Year Production by Area (BCF/D)



Glossary Of Terms

Decline rates are measures of total production losses over one year from producing wells. Decline rates vary over time and across regions. For example, in the shallow water GOM, gas wells beyond their first year of production collectively exhibit decline rates in excess of 40%. By comparison, onshore gas wells collectively reflect decline rates in the vicinity of 30%, excluding wells in their first year of production.

Drilling intensity refers to 12-month moving average gas-oriented rig counts behind new gas deliverability. PIRA's models typically lag drilling intensity relative to output from first-year wells by three months to account for the time lapse between drilling and initial production.

Dry gas production measures the amount of produced consumer-grade natural gas and equals marketed gas production less extraction loss.

Marketed production refers to total reservoir withdrawals less gas used for repressuring, quantities vented and flared, and non-hyrdocarbon gases removed in the treating or processing operations. Includes all quantities of gas used in field and processing plant operations.

New gas is a measure of the average production from wells started within the past 12-month period. New gas production is a function of drilling intensity multiplied by rig efficiency.

Old gas is a measure of production from wells older than one year and is a function of year-ago total gas and annual decline rates.

Onshore Mature Group (MG) regions include the Onshore Gulf of Mexico, Midcontinent and Permian Basin. Together, the Group represents the backbone of U.S. gas production, with about 50% of total U.S. output.

"Other" Onshore Mature Group refers to specific areas of the Onshore MG that are not modeled by vintage, namely Alabama, Florida and Mississippi.

PIRA's U.S. rig counts differ from Baker Hughes counts, owing to the substitution of Offshore Data Services' rig counts for the Offshore Gulf of Mexico. Also, Smith International gas/oil splits are applied to PIRA's regional rig counts to determine regional gas rig counts.

Production treadmill relates to the need for new gas deliverability to offset old gas production losses. The larger the production base, the larger the old gas well losses, given a constant decline rate. Similarly, the faster the decline rate, the larger the old gas well losses (and visa versa), given a constant production base.

Rig efficiency is a measure of average production from first year well per active gas rig. It is calculated by dividing the volume of first-year gas output by drilling intensity and is measured in MMCF/D per rig. Generally, there is an inverse relationship between drilling intensity and rig efficiency that reflects the deterioration in drilling prospect quality when drilling intensity increases and visa versa.

Vintage analysis relates to measuring and assessing production based on the dynamic inter-relationships between new gas output from gas-oriented drilling and older gas output when taking into account annual declines from post-first-year wells. PIRA's North American regional models and Producer Group Simulation models are built around "vintage analysis" that systematically tracks correlations between gas-oriented rig counts and gas produced from first-year gas wells.

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Eastern North America Energy • North American Natural Gas

Does Florida Remain Vulnerable to Fuel Disruptions from Hurricanes?

DECISION BRIEF

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KENNETH L. YEASTING, CERA Director, is an expert on the interstate natural gas pipeline and storage industries and also specializes in eastern North America gas and power markets. Mr. Yeasting focuses on issues related to gas prices and basis; pipeline flows and development; storage usage and development; and the impacts of liquefied natural gas on gas prices, gas flows, and the need for new infrastructure. He is the lead author of CERA's *Eastern Energy Monthly Briefing* and has authored numerous CERA reports on supply and demand impacts, market strategies, new development effects, and market trends. Before joining CERA, Mr. Yeasting had a long career at ANR Pipeline Company, where he held a number of executive positions. Most recently he was Director of Energy Forecasting, and also held the positions of Director of Revenue Forecasting, Director of Market Research and Planning, and Director of Strategic Planning, among others. With the ANR Storage Company he was Director of Planning and Regulatory Affairs and Director of Financial Planning and Control, among other positions. He also worked for the Michigan Consolidated Gas Company. Mr. Yeasting holds a BBA and an MBA from the University of Michigan.

DOES FLORIDA REMAIN VULNERABLE TO FUEL DISRUPTIONS FROM HURRICANES?

by Kenneth L. Yeasting

LINGERING VULNERABILITY

Florida relies on gas-fired generation to meet over 38 percent of the state's electricity requirements. Last year, gas deliveries into Florida were significantly disrupted by Hurricane Katrina. Gas service to Florida has been restored, even bolstered, with flows on Destin Pipeline Company from offshore at pre–Hurricane Katrina levels and all four gas processing plants in the Mobile, Alabama/Pascagoula, Mississippi, area operating. An increase in capacity at the Petal Gas Storage facility provides greater gas supply backup than last summer. Further, higher on-site power plant coal and oil product inventories in Florida have reduced the risk of disruption for coal- and oil-fired generation. However, petroleum coke inventories are running well below year-ago levels.

Despite these efforts to improve power plant fuel reliability, Florida remains vulnerable. A number of projects have been proposed that would by 2010 bring additional gas supplies from other areas to Florida. Several of these projects would improve the reliability of gas supplies into the Gulfstream Natural Gas System (Gulfstream).

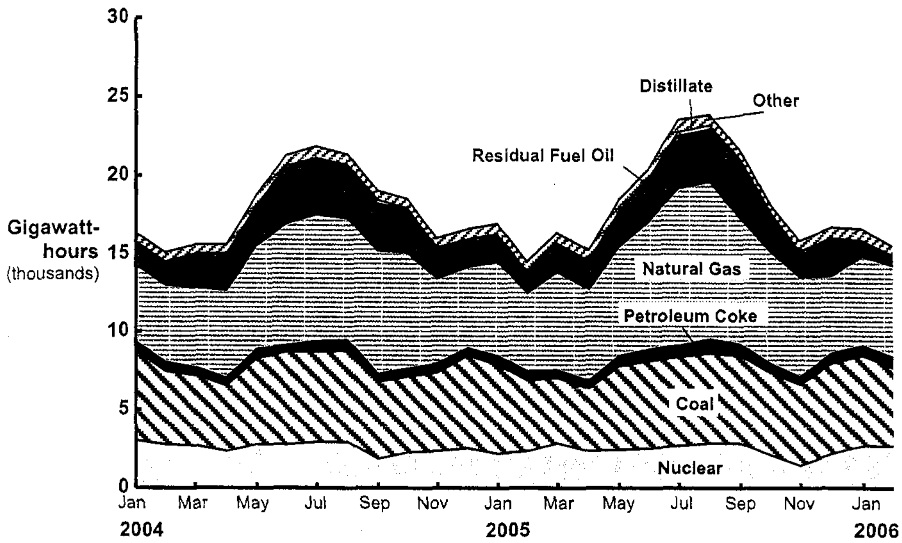
HURRICANE KATRINA EXPOSES RISKS

Florida's power sector relies heavily on natural gas, oil, and coal (see Figure 1). Last August, Hurricane Katrina significantly disrupted both natural gas flows into Florida and the ability to replenish oil and coal supplies used by Florida power generators.* Significant impacts included

- Throughput on Florida Gas Transmission (FGT) into Florida declined by about 200 million cubic feet (MMcf) per day to about 1,600 MMcf per day.
- Throughput on Gulfstream into Florida declined from about 950 MMcf per day to a low of 150 MMcf per day on August 29, 2005, the day after Hurricane Katrina hit.
- The Florida Reliability Coordinating Council's (FRCC) State Capacity Emergency Coordinator issued an alert expressing concern that residual fuel oil inventories could not be husbanded, as they were likely needed to cover the shortfall in gas deliveries. Florida, which does not have any oil product pipelines, relies on waterborne deliveries of oil, primarily barges from the central Gulf Coast. With many Gulf Coast ports damaged and several refineries offline, the FRCC was concerned about replenishing residual fuel oil inventories used to cover a natural gas shortfall.

*See the CERA Alert *Gulf Coast Damage from Katrina Threatens Reliability of Florida Electric System.*

Figure 1
Florida Generation



Source: Cambridge Energy Research Associates.
60605-2

- Florida also relies on waterborne deliveries of coal. TECO Energy reported that its coal terminal facility located in Davant, Louisiana, south of New Orleans, was flooded and without power and would have to rely on its 30-day supply of coal on the ground at its power stations.

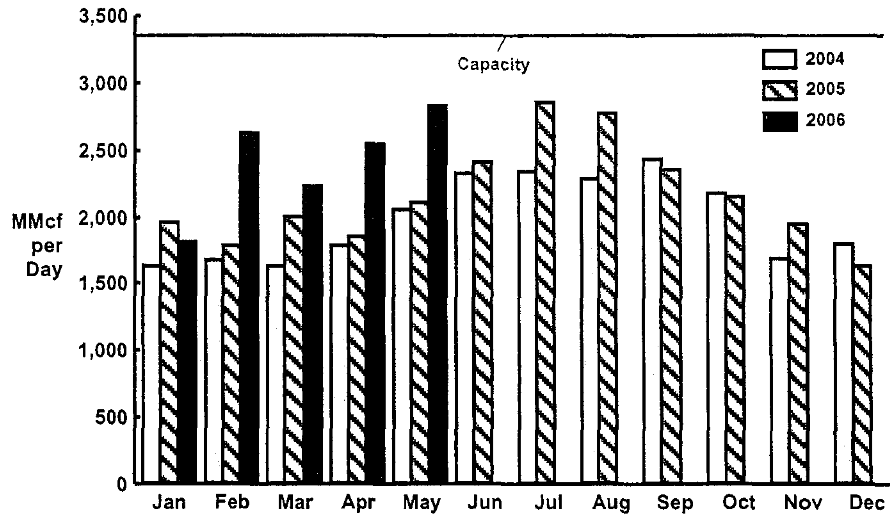
Throughput on FGT was not as severely affected as Gulfstream by Hurricane Katrina, as FGT has more robust access through pipeline interconnections to other gas supply sources and storage from South Texas to Mobile Bay in Alabama and Petal by Destin. In contrast, Gulfstream has access to gas supply sources in the Mobile Bay area only. Receipts from the four processing plants in Mobile Bay and from offshore production from Destin were at one point reduced to zero. Delays in restoring power delayed reactivation of at least two of the processing plants. Flows on Gulfstream partially recovered to 414 MMcf per day on September 1, 2005, with over 90 percent of the flow into Gulfstream represented by withdrawals from Petal with delivery to Gulfstream by Destin.

NATURAL GAS SUPPLY REMAINS VULNERABLE

Florida's natural gas supply remains vulnerable to disruption from hurricanes. Gulfstream remains especially vulnerable, as its gas supply currently comes almost exclusively from Mobile, Alabama/Pascagoula, Mississippi, area gas processing plants and offshore production from Destin. Since February, pipeline flows on FGT and Gulfstream into Florida are running significantly above year-ago levels, increasing Florida's reliance on at-risk gas supplies (see Figure 2).

Figure 2

Flows into Florida



Source: Cambridge Energy Research Associates.
60605-3

Pipelines flows on FGT and Gulfstream into Florida for May 2006 were 2,829 MMcf per day, an increase of 723 MMcf per day, or 34 percent, from May 2005. Over 70 percent of the increase occurred on the more vulnerable Gulfstream, although it has half the capacity of FGT (see Figure 3). The May increase in gas flows into Florida was likely the result of two factors:

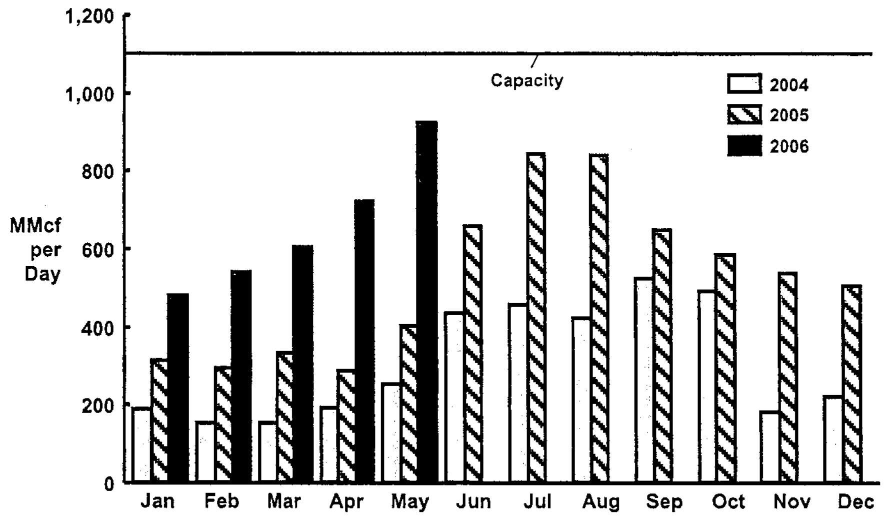
- an increase in electric demand, as May 2006 in Florida had 2.5 percent fewer cooling degree-days than normal, whereas May 2005 had 8.3 percent fewer cooling degree-days than normal

- a switch by dual-fuel steam plants to natural gas from residual fuel oil as the Henry Hub gas price went from \$0.15 per million British thermal units (MMBtu) above 1% Gulf Coast residual fuel oil for May 2005 to \$1.93 per MMBtu below for May 2006

For this summer, CERA expects electric demand to be somewhat higher owing to economic growth, reduced hurricane outages, and a return to normal weather. Last summer Florida had 0.9 percent more cooling degree-days than normal. CERA also expects that natural gas prices will remain well below residual fuel oil prices this summer.

As noted above, last year withdrawals from Petal were the primary source of gas supply for Gulfstream immediately following Hurricane Katrina. In December 2005, Petal placed a third storage cavern into operation, increasing working capacity by 2,400 MMcf to 11,900

Figure 3
Gulfstream Flows into Florida



Source: Cambridge Energy Research Associates.
60605-4

MMcf and increasing deliverability by 300 MMcf per day to almost 1,200 MMcf per day. The increase in deliverability improves the ability of Petal withdrawals to backstop a loss of gas supply going into Gulfstream.

OIL AND COAL INVENTORY SITUATION HAS IMPROVED

Inventories of liquid oil products and coal held by Florida generators are higher than year-ago levels, improving Florida's ability to absorb a fuel supply disruption, but petroleum coke inventories are well below year-ago levels.

Oil Inventories Up Substantially

Residual fuel oil is an important source of fuel for Florida generation. For 2005 almost 13 percent of Florida's total generation was from residual fuel oil–fired generation. Further, Florida dual-fuel steam plants play an important balancing role, as pipeline capacity into Florida can be constrained during peak demand periods and Florida has no natural gas storage. Florida generators generally maintain substantial oil product inventories to facilitate this balancing role and to minimize the impact of oil supply disruptions on the availability of generation.

For January and February, the latest months for which data are available, liquid oil product inventories of Florida generators were running well above year-ago levels (see Figure 4). Current inventories represent 80 days of supply based on annual average usage. This level of oil inventories is probably more than adequate. One factor that should contribute to the maintenance of higher oil inventories is that since February natural gas prices have been at or below residual fuel oil prices.

Coal Inventories Up Slightly

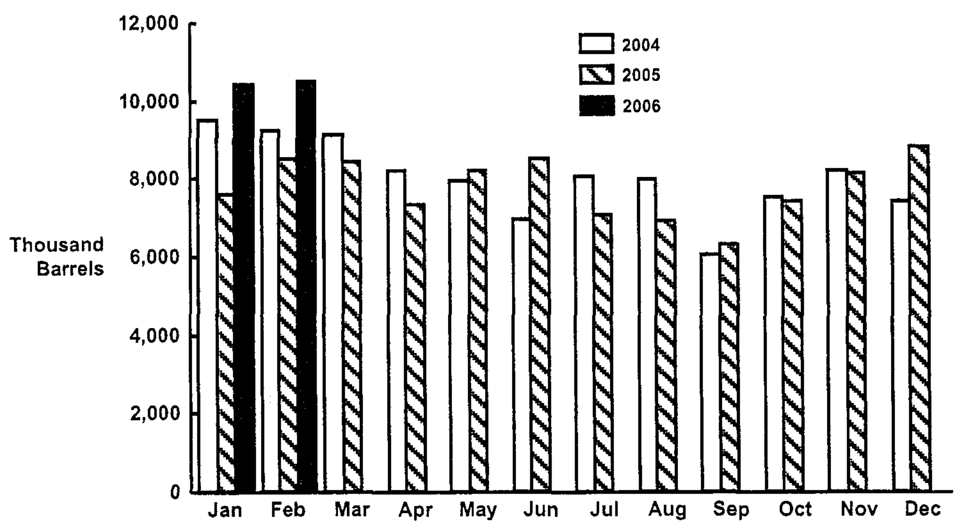
For January and February, the latest months for which data are available, coal inventories of Florida generators were running above year-ago levels but well below 2004 levels (see Figure 5). Florida receives coal by rail, by barge across the Gulf of Mexico from New Orleans, and by oceangoing vessels. The shipping schedules of barges and oceangoing vessels can be disrupted by hurricanes. What was unique last year was that the New Orleans port facilities were heavily damaged by Hurricane Katrina. This disrupted the transshipment to Florida of domestic coal received in New Orleans from the Illinois Basin. Current inventories represent 47 days of supply based on annual average usage. This level of coal inventories is probably adequate.

Petroleum Coke Inventories Are Down

Florida meets 3.5 percent of its generation requirement with petroleum coke. Year over year, petroleum coke inventories are well below last year's levels but about even with 2004 levels (see Figure 6). Current inventories represent 35 days of supply based on annual average usage. This level of petroleum coke inventories is probably adequate.

Figure 4

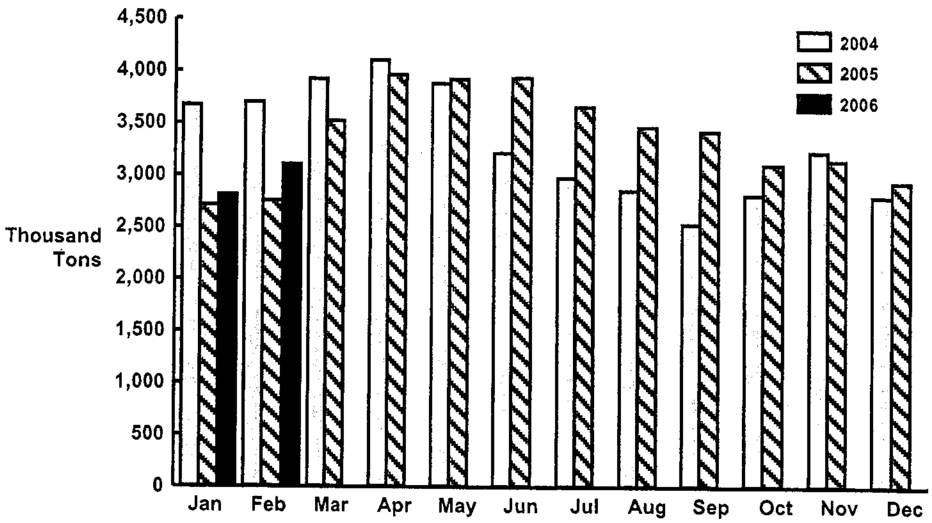
Florida Generator Petroleum Liquid Inventories



Source: US Energy Information Administration Form 920.
60605-5

Figure 5

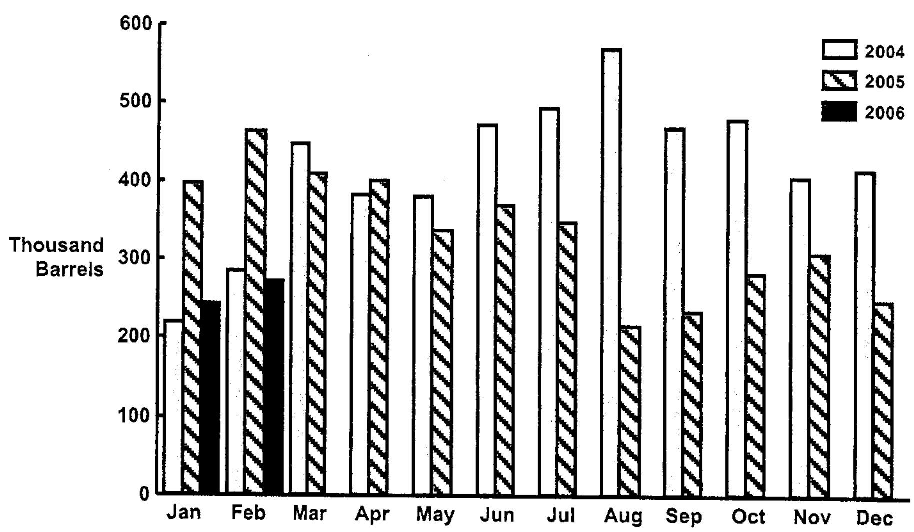
Florida Generator Coal Inventories



Source: US Energy Information Administration Form 920.
60605-6

Figure 6

Florida Generator Petroleum Coke Inventories



Source: US Energy Information Administration Form 920.
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DIVERSIFICATION KEY TO LONG-TERM RELIABILITY OF FUEL SUPPLY

A major key to improving the reliability of Florida's fuel supply for generation is to diversify its gas supply options, especially in the near term, as diversifying generation technologies can take several years. Three groups of gas supply projects have been proposed to do just that, comprising new pipelines to Gulfstream from other gas supply areas, liquefied natural gas (LNG) terminals, and storage.

Several pipeline projects have been proposed to bring gas to Gulfstream from other gas supply areas, including competing projects by Gulfstream's partners:

- Duke Energy Gas Transmission, which owns half of Gulfstream, has filed a request to begin the prefiling process for a 1,000 MMcf per day Southeast Supply Header project from the Perryville Hub in northern Louisiana to interconnections with FGT and Gulfstream. The Southeast Supply Header would be a joint venture with CenterPoint Energy, with an expected online date in 2008. CenterPoint has proposed a 1,200 MMcf per day project from East Texas to the Perryville Hub, to be operational this year. These combined projects would give Florida direct access to growing East Texas production.

- Transcontinental Gas Pipe Line Corporation (Transco) recently held an open season for a 750 MMcf per day Production Area Mainline expansion from Station 45 in Louisiana to Station 85 in Alabama. Transco also held an open season for a 700 MMcf per day Mobile Bay South expansion of its Mobile Bay lateral from Station 85 to Gulfstream. Both projects are scheduled for start-up in 2008. Williams, Transco's parent, owns half of Gulfstream.

- Columbia Gulf Transmission recently held an open season for an expansion and extension of its east lateral from Venice, Louisiana, to Gulfstream at Pascagoula, Mississippi. This project would begin operation in 2009.

- Enbridge Energy Partners recently held an open season for a 1,000 MMcf per day Southeast Texas Expansion project from southeast Texas to Clarke County, Mississippi, where it would interconnect with Destin, which could back-haul gas to Gulfstream. This project would start operation in 2009.

At present there are still four active LNG projects primarily targeting Florida:

- Southern Natural Gas's 500 MMcf per day Cyprus lateral has been filed with the Federal Energy Regulatory Commission. This expansion would bring gas from the Elba Island LNG terminal in Georgia to an interconnection with FGT near Jacksonville, Florida, and would be phased in from 2007 through 2010.

- Calypso US Pipeline (Calypso), a subsidiary of SUEZ Energy North America, has filed to amend its approved pipeline that was intended to bring LNG to southern Florida from the Bahamas. Calypso is now proposing a buoy terminal about 10 miles offshore Florida with LNG deliveries by ships fitted with onboard regasification. The 832 MMcf per day pipeline is proposed to be in service in 2010.

- Chevron has filed to build the Casotte Landing Natural Gas Import Terminal in Pascagoula, Mississippi. This LNG terminal would have base-load send-out of 1,300 MMcf per day with a proposed in-service date of 2010. This terminal would be connected to Gulfstream and four other pipelines.

- Gulf LNG Energy has filed to build the Clean LNG Energy terminal in Pascagoula, Mississippi. This LNG terminal would have base-load send-out of 1,300 MMcf per day with a proposed in-service date of 2009. This terminal would be connected to Gulfstream and at least one other pipeline.

Petal has begun construction of a 5,000 MMcf working capacity expansion with 500 MMcf per day expansion of deliverability and an expected in-service date of 2008.

CONCLUSION: IMPLICATIONS FOR RELIABILITY OF FUEL SUPPLY

Florida's natural gas supply remains vulnerable to hurricane disruptions this summer, especially for Gulfstream, whose gas supply comes primarily from the Mobile, Alabama/Pascagoula, Mississippi, area. However, an increase in capacity at the Petal facility provides greater gas supply backup than last summer. Further, higher generator coal and oil product inventories have reduced the risk of disruption for coal- and oil-fired generation. Nevertheless, until greater gas supply diversity is achieved through one or more of the projects noted above, Florida remains at risk for significant gas supply disruptions. ■

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North American Natural Gas

North American Gas Capacity Race

Can Unconventional Gas Offset the Increased Decline in the Gulf of Mexico?

PRIVATE REPORT®

NORTH AMERICAN GAS CAPACITY RACE: CAN UNCONVENTIONAL GAS OFFSET THE INCREASED DECLINE IN THE GULF OF MEXICO?

OVERVIEW

This Private Report, which captures CERA's outlook for North American gas productive capacity to 2012, chronicles the key issue for the industry in North America: despite record gas-related drilling activity, supply is struggling to avoid a decline.

Capacity in North America is projected to remain on an "undulating plateau," as CERA author Robert Esser describes it, with little change through 2010 before a moderate decline sets in through 2012 and beyond. A 2.6 billion cubic feet (Bcf) per day decline from 2004 in the United States by 2012 is largely offset by a 2.5 Bcf per day increase in Canada. This outlook is close to and directionally identical to CERA's previous outlooks for North American natural gas supply. While there have been both supply disappointments (e.g., the shelf and deepwater in the Gulf of Mexico) and upside surprises (e.g., a surge in Canadian coal seam methane [CSM]), these have tended to net for an outlook that places total supply quite close to CERA's more recent outlooks.

"The Gulf of Mexico is a major determinant of US capacity," writes Esser. The projected near-term peak in deepwater capacity, when combined with the ongoing decline on the shelf, has increased the overall decline in the Gulf of Mexico in CERA's view to 4.4 Bcf per day between 2004 and 2012.

Esser highlights the potential of unconventional gas—tight sands, shale gas, and CSM to increase capacity. Currently representing over 75 percent of rig activity, unconventional capacity is projected to increase by 5.1 Bcf per day between 2004 and 2012, thus offsetting the decline in the Gulf of Mexico. This resource remains one of the few potential upsides in the outlook.

For the near term, dry gas capacity in the US Lower 48 is projected to continue to decline slightly into 2007, losing around 0.3 Bcf per day. The increase in unconventional gas in the Gulf Coast and Rockies is offset by the declining Gulf of Mexico and Permian and San Juan Basins. A continued high rate of drilling could ultimately result in a slight increase in capacity in the near term.

Capacity in Canada is projected to increase slowly to 2010 with growth in the Western Canadian Sedimentary Basin (WCSB), blending with the arrival of the Mackenzie Delta gas in 2010. Unconventional gas—CSM and tight sands—is the primary source of the growth in the WCSB.

This outlook reconfirms CERA's repeated message about the North American gas industry: it has transitioned permanently from a market characterized by surplus supply and gas-on-gas competition to one marked by constrained continental supply, and thereby constrained growth wrought from competition for available supply. CERA's outlook points to a significant opportunity for new supplies, one that has captured the attention of the global energy industry. Indeed, CERA expects liquefied natural gas to play a significant and accelerating role in North America, from serving 3 percent of demand in 2004 to 13 percent in 2010 to about 25 percent by 2020.

—Daniel Yergin
May 2005

NORTH AMERICAN GAS CAPACITY RACE: CAN UNCONVENTIONAL GAS OFFSET THE INCREASED DECLINE IN THE GULF OF MEXICO?

by Robert Esser

INTRODUCTION

Although drilling activity related to natural gas in both the United States and Canada has been at record levels, little effect has been seen on productive capacity. With increased drilling activity directed to unconventional gas—tight sands, shale gas, and coal seam methane (CSM)—this component has responded to record drilling levels in the Rockies, the Bossier and Cotton Valley plays in East Texas and north Louisiana, and the Barnett shale in north central Texas. In Canada a reversal of the wellhead capacity decline in the Western Canadian Sedimentary Basin (WCSB) can be attributed to tight sands and CSM plus the Monkman play in British Columbia. High drilling levels have also tended to reduce decline rates in the Permian and San Juan Basins and reversed the decline in Oklahoma and Canada. CERA has consistently felt that the consensus outlook for a permanent decline in the WCSB was unlikely to occur.

A key signpost for North American capacity, and a focus of this Private Report, is the ability of unconventional gas to offset the projected increased decline in the Gulf of Mexico.

Because the rig count is currently so close to full utilization, any increase in overall North American productive capacity will be limited; the only sources of new rigs will be from drilling companies ordering new rigs or from rigs being switched to gas from oil-related drilling (24 rigs have done so since February 2005). In Canada, 34 new rigs have been added to the fleet during the past 12 months. Most of these are coiled tubing rigs for shallow and mid-depth drilling.

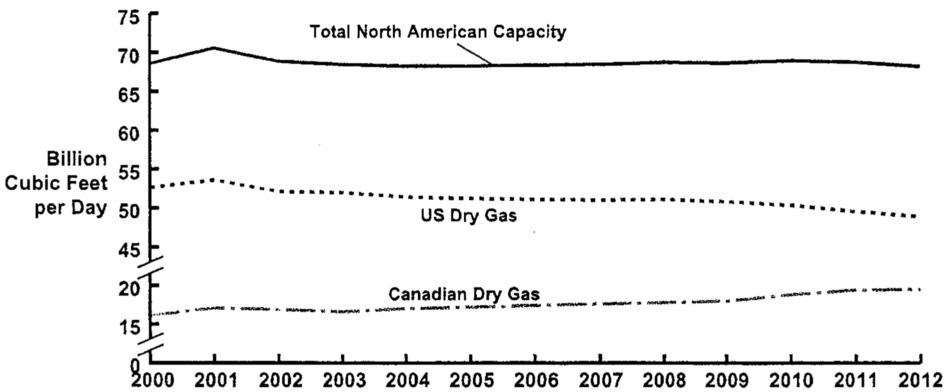
NORTH AMERICAN DRY GAS OUTLOOK

After peaking at 70.8 billion cubic feet (Bcf) per day in 2001, North American dry gas productive capacity is projected to fluctuate on an undulating plateau between 68.4 and 69.2 Bcf per day to 2012 (see Figure 1 and Table 1). Beyond 2010, accelerated declines are projected to overtake supply additions. A 2.6 Bcf per day decline in wellhead capacity in the United States (from 51.5 Bcf per day in 2004 to 48.9 Bcf per day in 2012) is largely offset by a 2.5 Bcf per day increase in Canada (from 17.0 Bcf per day in 2004 to 19.5 Bcf per day in 2012).

The slow decline in the United States, following the 53.7 Bcf per day peak in 2001, begins to increase after 2010 as declines spread to all areas except the Rockies. Canadian capacity reached a low point of 16.6 Bcf per day in 2003, due mainly to the decline in the Ladyfern field, and from this point is projected to increase steadily throughout the period to 2012 and beyond with increased production from the WCSB, followed by the arrival of Mackenzie Delta gas in 2010.

Figure 1

North American Dry Gas Productive Capacity
(billion cubic feet per day)



North American Dry Gas Capacity (Bcf per day)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
US	52.7	53.7	52.2	52.1	51.5	51.3	51.2	51.1	51.2	50.9	50.4	49.6	48.9
Canada	16.1	17.1	16.9	16.6	17.0	17.2	17.4	17.6	17.8	18.0	18.8	19.4	19.5
Total	**68.8**	**70.8**	**69.1**	**68.7**	**68.5**	**68.5**	**68.6**	**68.7**	**69.0**	**68.9**	**69.2**	**69.0**	**68.4**

Source: Cambridge Energy Research Associates.
Updated April-1 2005
40916-39

Table 1

North American Dry Gas Productive Capacity Outlook
(billion cubic feet per day)

	2000	2001	2004	2005	2007	2010	2012
US Lower 48	53.9	54.9	52.7	52.5	52.4	51.8	50.4
Alaska	1.4	1.4	1.3	1.3	1.1	1.0	0.9
Total US Wet	55.3	56.3	54.0	53.8	53.5	52.8	51.3
Total US Dry	52.7	53.7	51.5	51.3	51.1	50.4	48.9
Canadian Dry	16.1	17.1	17.0	17.2	17.6	18.8	19.5
Total North America	**68.8**	**70.8**	**68.5**	**68.5**	**68.7**	**69.2**	**68.4**

Source: Cambridge Energy Research Associates.
Updated April 2005.

LOWER-48 WET GAS OUTLOOK

From 2004 through 2009, US lower-48 wet gas capacity is expected to be on an undulating plateau at around 52.5 Bcf per day. The addition of 0.8 Bcf per day from the eastern Gulf of Mexico in 2008 will slow the decline in the Gulf of Mexico for one year, interrupting the gradual decline in the US Lower 48. Increased capacity in the Rockies, the Gulf Coast, the Mid-Continent, and the eastern United States offsets an increase in the capacity decline in the Gulf of Mexico and moderate declines in the Permian and San Juan Basins and the West Coast (see Figures 2 and 3 and Table 2). After 2010 the decline spreads to all regions except the Rockies, increasing the overall decline, interrupted only by gas from Alaska, which is assumed to achieve first flow in 2015.

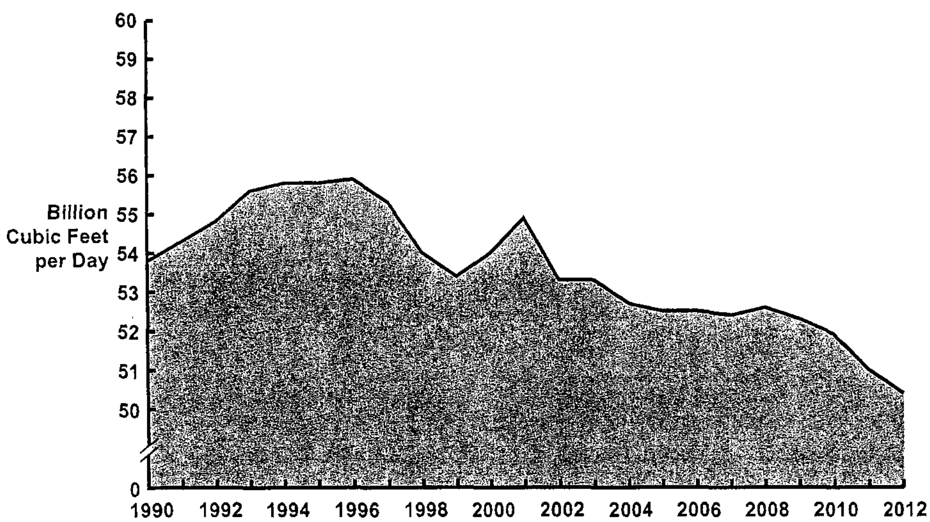
WHAT COULD THROW THIS PROJECTION OF CAPACITY OFF?

The projection of US lower-48 capacity could be thrown off by two key events:

First, if the high rate of unconventional gas drilling actually adds more capacity than expected, not only in the current hot spots but also in evolving ones, and if the expected declines in the Permian and San Juan Basins actually become smaller or reverse, US lower-48 capacity could increase slightly, by 0.5 to 1.0 Bcf per day, in the next few years. This trend has been occurring in some areas and has been noticed in successive updates that show smaller decline rates than originally expected. One obstacle to the growth of unconventional

Figure 2

US Lower-48 Average Annual Wet Gas Productive Capacity



Source: Cambridge Energy Research Associates.
Updated April 2005
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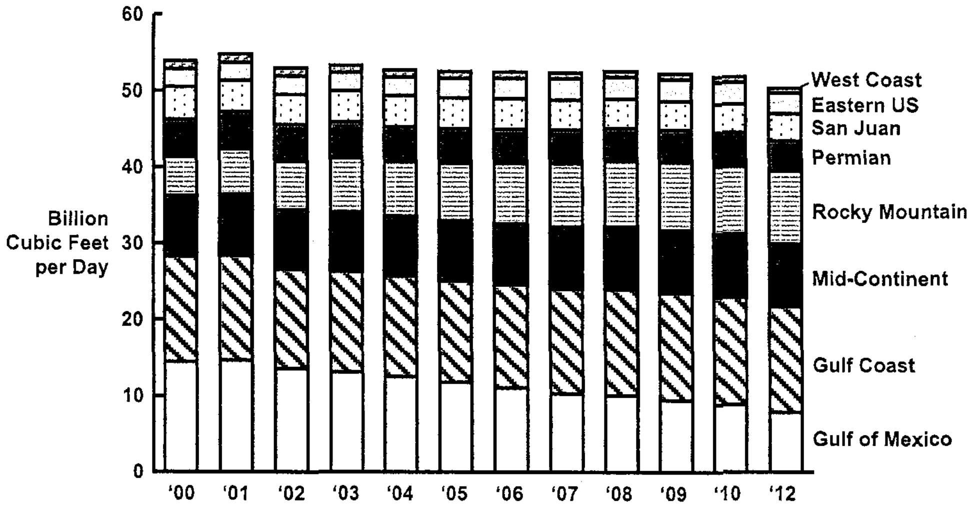
Figure 3
Regional Wet Gas Capacity—US Lower 48



Source: Cambridge Energy Research Associates.
Updated April 2005.
40916-49

gas much beyond our outlook is that the rig count is nearing full utilization. In some cases increases in rigs have required operators to make deals with drilling companies involving the construction of new rigs. Thus the upside from unconventional gas is limited in magnitude and timing.

On the other hand, a second event that could affect the outlook is the concern of some companies over surging drilling and completion costs and a shortage of experienced drilling crews. Some companies could actually curtail some drilling activity in response to these issues. Earlier this year as many as six active operators had made tentative decisions to possibly curtail some drilling. Should more companies trim drilling in response to higher costs, the smaller capacity growth in some areas could result in a more rapid US lower-48 decline than is currently expected. At this point, companies have the incentive to develop efficiencies to moderate the effect of higher costs.

COMPANY STRATEGY TOWARD GAS

In North America there have been two opposite strategies toward developing gas production. The supermajors have continued to sell off onshore assets to the eager and receptive large independents, opting instead to emphasize the deepwater Gulf of Mexico and the shallow-water shelf, focusing on the deep and ultradeep shelf gas plays. Also supermajors are involved with liquefied natural gas (LNG) development. It is noteworthy that seven of the top ten North American natural gas producers are pursuing LNG development in North America.

Table 2

Wet Gas Capacity Outlook by Region

(billion cubic feet per day)

	2000	2002	2003	2004	2005	2006	2007	2008	2009	2010	2012
Gulf of Mexico [1]	14.64	13.57	13.13	12.55	11.80	11.04	10.29	10.05	9.45	8.87	7.85
Gulf Coast [2]	13.68	13.08	13.22	13.20	13.33	13.57	13.80	14.01	14.09	14.11	13.87
Mid-Continent [3]	7.96	7.84	7.80	7.85	7.91	8.01	8.12	8.14	8.20	8.26	8.20
Rocky Mountains [4]	5.08	6.51	7.04	7.12	7.50	7.90	8.28	8.63	8.94	9.19	9.60
Permian Basin [5]	4.92	4.82	4.76	4.62	4.55	4.49	4.42	4.33	4.24	4.15	3.91
San Juan Basin [6]	4.21	4.06	4.05	4.05	4.02	3.96	3.90	3.84	3.78	3.72	3.60
Eastern US [7]	2.35	2.41	2.39	2.45	2.57	2.69	2.79	2.85	2.85	2.86	2.71
West Coast	1.04	1.00	0.93	0.87	0.84	0.81	0.78	0.75	0.72	0.69	0.62
Total Lower 48	**53.88**	**53.29**	**53.32**	**52.71**	**52.52**	**52.47**	**52.38**	**52.60**	**52.27**	**51.85**	**50.36**
Alaska	1.40	1.40	1.35	1.30	1.25	1.20	1.15	1.10	1.05	1.00	0.90
Total US	**55.28**	**54.69**	**54.67**	**54.01**	**53.77**	**53.67**	**53.53**	**53.70**	**53.32**	**52.85**	**51.26**

Source: Cambridge Energy Research Associates.
1 Includes Louisiana, Texas, and Alabama.
2 Includes Texas RRC 1-6, Louisiana, Mississippi, Alabama onshore, and Florida.
3 Includes Texas RRC 7B, 9, 10; Kansas, Oklahoma, and Arkansas.
4 Includes Montana, North Dakota, North Colorado, Utah, Wyoming, and Arizona.
5 Includes southeast New Mexico, and Texas RRC 7C, 8, 8A.
6 Includes northwest New Mexico, and Southern Colorado.
7 Includes Michigan, Kentucky, Ohio, New York, Pennsylvania, Virginia, and West Virginia.
Updated April 2005.

Large independents are generally targeting the unconventional gas resource plays in both the United States and Canada, with several of the leading companies pulling back from the Gulf of Mexico. The Rockies and East Texas are the leading areas of interest, with acquisition and strong drilling activity as a dominant strategy (see Table 3). In response to high prices, some companies are increasing previously-established drilling budgets. These companies are also seeking evolving unconventional hot spots, especially possible tight reservoirs and gas shales in older fields in mature areas made economic with the current

Table 3

Recent E&P Trends Affecting the Gas Capacity Forecast

General

- Emphasis continues on long-lived unconventional reserves (coal seam, tight sands/shales with a prolonged low decline after steep initial decline) with "gas mining," which involves low-risk, closely spaced wells, highly efficient exploitation not economic at previous low prices (i.e., Rockies, East Texas)
- Supermajors shift to LNG and continue to exit from onshore areas
- Reduced exploration with emphasis on low-risk exploitation of onshore niche areas
- Large independents continue to focus on the purchase of disposed assets of supermajors in core areas or entry into desired new areas
- Strong emphasis on the Rockies, with rig activity well above record 2001 levels and companies continuing to pursue entry, but access is still a problem

Gulf of Mexico

- Exploration emphasis is shifting to Atwater Foldbelt area and ultradeepwater Eocene (Lower Tertiary) oil play with much exploration and appraisal drilling
- Continued slowed pace of sanction of deepwater discoveries
- Shift to deep and ultradeep shelf play by supermajors and others
- No pickup in shallow-shelf drilling to 15,000 feet, likely due to lack of prospects
- Gas drilling in deep water is centered on short cycle time prospects near existing infrastructure or the eastern Gulf

Source: Cambridge Energy Research Associates.

high gas price and advances in fracturing technology. Companies that have not accumulated a large inventory of undrilled locations will have difficulty maintaining current production levels. In the Gulf of Mexico some of these companies are participating in both the deep water and the deep and ultradeep shelf plays.

The dominant large independents are emphasizing the exploitation of undrilled locations in onshore resource plays while placing much less emphasis on exploration.

With so much attention directed to unconventional gas, should gas prices drop because of weather, a slowdown in the economy, and sudden large supplies of LNG, the ensuing downturn in drilling activity would be similar to the 2001 to 2002 period. It is noteworthy that drilling increases are constrained by the lack of available rigs, and thus the drilling upside is relatively insensitive to price while the drilling downside is highly sensitive to price. A sudden drop in wellhead capacity, due to a loss of so many new wells with high initial production levels, would allow the decline rate to take over, restoring higher prices and thus supporting drilling again after a short time.

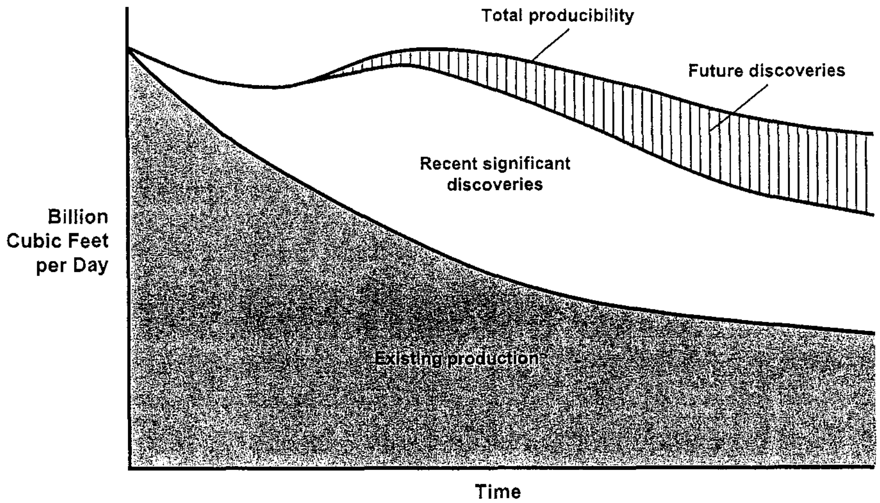
CONTEXT AND METHODOLOGY

CERA projects US wellhead capacity on a wet gas basis, i.e., with the natural gas liquids (NGLs) left in the gas.

Productive capacity refers to peak annual capacity, excluding the effects of seasonal and temporary factors such as weather (hurricanes in the Gulf and well freeze-offs) and regional price distortions related to local demand and distribution problems. At recent price levels, gas producers have a strong incentive to get their gas to market, and gas production is very close to gas capacity. On average, only about 2 percent of gas capacity is expected to be unavailable at any given point in the future. CERA's projection of gas capacity is based on the analysis of three basic components: existing production, including expected declines; recent significant discoveries; and the expectation of production from future discoveries based on the current and expected pace of exploration, recent discovery experience, and the timing required for development (see Figure 4). CERA's price outlooks further anticipate changes to downstream infrastructure, which may constrain wellhead supply from reaching markets. Inclusion of future discoveries differentiates CERA's outlook from others. This stepped methodology applies mostly to the Gulf of Mexico as most of the onshore resource plays depend not on exploration, but on a continued high level of drilling and on company decisions to increase drilling to exploit large, undeveloped resource plays.

The near-term outlook is activity-based by basin combined with recent production levels, modified by current and expected near-term activity levels, superimposed on CERA's expectation of reserves and discovery potential, the elimination of the effect of temporary disruptions, and the pace and timing of development of expected new production. Some industry analysts, when examining scattered individual quarterly company production comparisons with previous quarters, have called for declines of up to 5 percent over the same time periods, disregarding the reason for the decline. CERA believes that company production comparisons provide a misleading picture of the future.

Figure 4
Components of Producibility



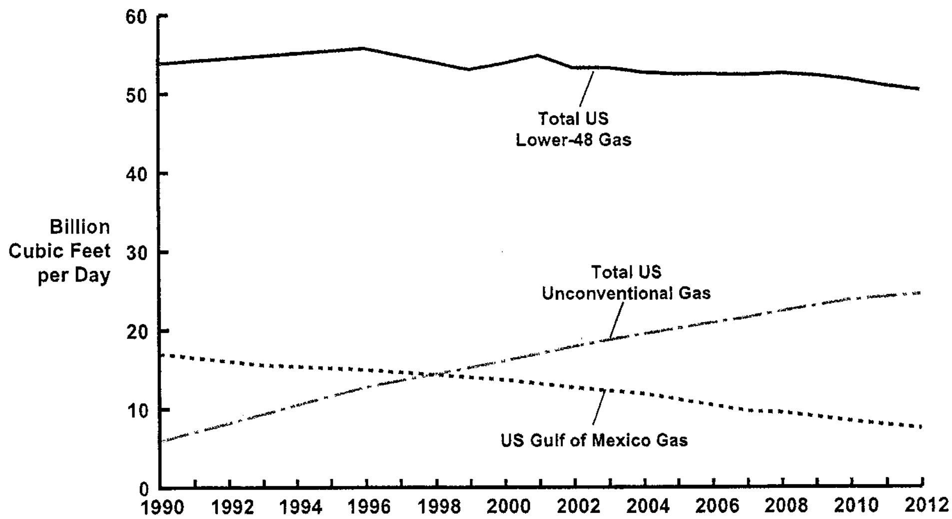
Source: Cambridge Energy Research Associates.
2005
40916-77

UNCONVENTIONAL GAS: THE OFFSET TO THE INCREASED DECLINE IN THE GULF OF MEXICO

Unconventional gas plays, consisting of tight sands, shale gas, and CSM, are on track to constitute close to half of the total gas production in the United States by 2012. Most of the areas with strong drilling activity (at least 75 percent of the current gas-related rig count) are targeting unconventional gas, the only component of North American supply that is currently increasing (see Figure 5). The 5.1 Bcf per day increase from 2004 to 2012 in unconventional gas is sufficient to offset the 4.4 Bcf per day decline in the Louisiana/Texas portion of the Gulf of Mexico to 2012.

US lower-48 unconventional gas capacity began to increase rapidly in the 1990s from 5.9 Bcf per day in 1990 to 16.0 Bcf per day in 2000, led primarily by CSM in the San Juan and Powder River Basins and tight sands in all areas, spurred by Section 29 tax incentives. Since 2000, unconventional gas capacity has increased from 16.0 Bcf per day to 19.4 Bcf per day in 2004, with further growth to 24.6 Bcf per day projected for 2012 (see Table 4).

Figure 5
Rapid Growth of US Lower-48 Unconventional Gas



Source: Cambridge Energy Research Associates.
April 2005
40916-76

Table 4

US Unconventional Gas Outlook

(billion cubic feet per day)

	1990	1996	2000	2002	2004	2007	2010	2012
Coal seam methane	0.55	2.74	3.96	4.58	4.83	5.16	5.40	5.56
Tight sands	4.93	9.19	10.68	11.89	13.00	14.50	16.20	16.60
Shale gas	0.41	0.88	1.40	1.42	1.60	1.90	2.20	2.40
Total	**5.89**	**12.81**	**16.04**	**17.89**	**19.43**	**21.56**	**23.80**	**24.56**
Percent of total production	10.90	23.00	29.00	32.70	36.00	40.30	45.00	47.90

Source: Cambridge Energy Research Associates.
Updated April 2005.

Unconventional gas plays tend to provide huge, steady, long-lived reserves at low risk and at predictable production rates; however, they can be difficult to produce because of low reservoir permeability and the production mechanism. Unconventional reserves are not generally the result of recent discoveries but include existing reservoirs, reservoirs that were too high cost to exploit not so many years ago but have become economic thanks to the recent higher prices combined with new technology. The gas reservoirs in many cases are sorption reservoirs where gas is stored by absorption to the matrix, and the gas must be released by a drop in pressure before it can be produced. These wells are generally low capacity producers and have a characteristic production profile of a rapid initial decline within the first year followed by low decline rates, resulting in long-lived reserves. This profile compares with the typical conventional gas reservoir profile of a higher initial production followed by a rapid decline to reservoir depletion. The reservoirs have homogeneous characteristics and are typically continuous with large areal extent and in most cases are controlled by geologic trap-forming factors as in conventional oil and gas fields.

The initial development of unconventional gas reserves was inspired by US tax credits in the 1980s. Unconventional resources in the United States are almost twice the size of conventional reserves (185 trillion cubic feet [Tcf]) and are estimated by the US Geologic Survey at 350 Tcf, of which 185 Tcf occurs in tight sands. The Rockies are thought to contain 169 Tcf of unconventional gas. There are numerous estimates of reserves and potential resources of unconventional gas, and many of these estimates include some likely uneconomic resources. It is important to note that the volume of unconventional reserves and resources exceeds known proved reserves and conventional undiscovered potential. However, evolving areas of probable unconventional gas are becoming apparent as companies seek new areas and overlooked possible reservoirs in existing fields with the potential to produce gas (see Figure 6).

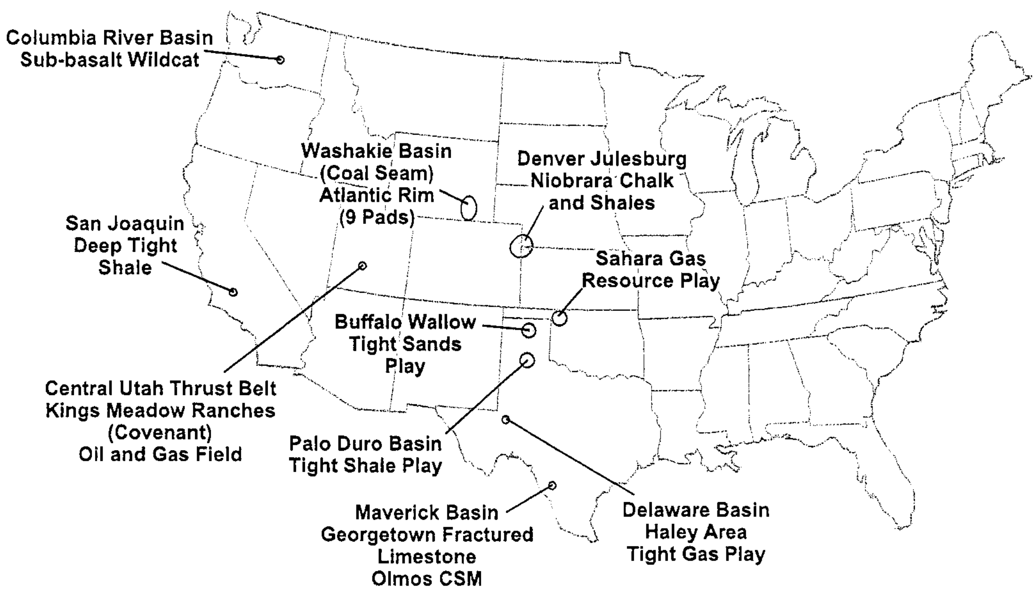
Much of the increase in expectations from unconventional gas has resulted from finding the optimum well spacing to recover more reserves utilizing updated multistage fracturing technology. Thus the Jonah field in Wyoming has had well spacing (the density of wells) reduced from the original 160 acres to 20 acres, and an application to go to 10 acres is awaiting approval. The reduction in spacing, increasing the density of development wells, and development of the entire package of sands in this field have increased gas recovery from 20–40 percent to 60–75 percent of the reserve. Likewise the Pinedale field, also in Wyoming, has had spacing reduced to 20 acres, resulting in numerous undrilled locations.

The projected strong growth in unconventional gas depends upon continued innovations in drilling, reduced well spacing, completion technology, overall land access, and removal of delays in well permitting.

It is important to look at the production response to increases in gas-related rig activity. From 1999 to 2001 an increase of almost 700 rigs, with unconventional gas the predominant target, resulted in an increase in capacity of only 1.7 Bcf per day due largely to three plays: Bossier Sand, Powder River CSM and the deepwater Gulf of Mexico. Note that

Figure 6

Evolving US Lower-48 Unconventional Gas Hot Spots



Source: Cambridge Energy Research Associates.
April-1 2005
40916-75

the deepwater play was a long lead time play with several large fields coming onstream in this time frame and thus was not a response to heightened drilling activity. Thus only the Rockies registered a significant supply response to activity in the 1999–2001 drilling boom. For the most recent increase in rig activity of 585 rigs between 2002 and mid-2005, which resulted in a new record for US gas-related drilling, productive capacity in 2005 is projected to have declined by 0.9 Bcf per day from the 2002 low point in drilling, largely due to the decline in the Gulf of Mexico (-1.8 Bcf per day), partially offset by a 1.0 Bcf per day increase in the Rockies. The increase in the Rockies and the surprising smaller-than-expected declines in other areas can be attributed solely to increased unconventional gas. It is evident that even very strong drilling activity targeting unconventional gas does not add large new production because of the small individual well production capabilities. Many wells are required to add small amounts of production.

Even though it is evident that more drilling is required to increase production, the lack of rig and personnel availability will moderate any increase in drilling.

UNCONVENTIONAL GAS—TIGHT GAS SANDS

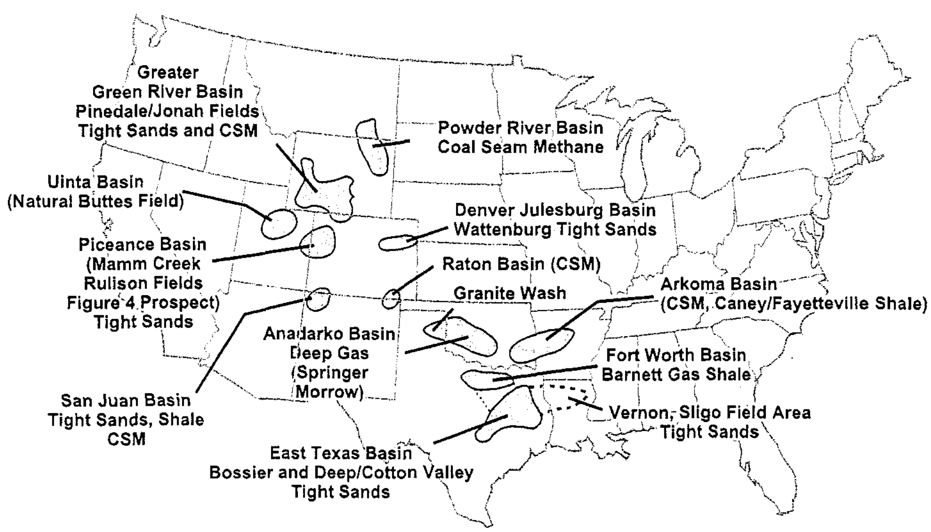
By far the largest component of unconventional gas is tight gas sands, which reached 13 Bcf per day in 2004 and is projeccted to reach 16.6 Bcf per day in 2012. Tight gas sands are fine-grained sandstone formations with permeability of less than 0.1 millidarcy. They are characteristically of widespread areal extent, usually overpressured, and occur in most geologic basins. The most active areas of tight sand development are East Texas and north Louisiana, the San Juan Basin, the Green River Basin in Wyoming, the Permian Basin of West Texas, and southeast New Mexico (see Figure 7). In the late 1990s, South Texas produced the most tight gas (2.4 Bcf per day), followed by the Rockies (1.6 Bcf per day), East Texas (1.5 Bcf per day), the San Juan Basin (1.4 Bcf per day), and the Permian Basin (0.9 Bcf per day).

Also many of the largest US gas fields involve tight sands. These include the Carthage field in East Texas, the Jonah and Pinedale fields in the Green River Basin in Wyoming, the Wattenburg field in Colorado, and much of the San Juan Basin.

Important tight gas sand reservoir targets include the Cotton Valley/Bossier sand play in East Texas, the overpressured Lance sand in the Greater Green River and Wind River Basins in Wyoming, the Williams Fork/Mesaverde in the Rulison and Mamm Creek fields in the Piceance Basin in Colorado, the Vicksburg and the Lobo (Wilcox) field in South Texas, the Mesaverde and Dakota formations in the San Juan Basin, and the Canyon sand in the Ozona field in the Permian Basin.

Figure 7

Current Unconventional US Lower-48 Gas Hot Spots



Source: Cambridge Energy Research Associates.
Updated May 2005
40916-45

UNCONVENTIONAL GAS—SHALE GAS

Shale gas is an increasing component of unconventional gas, occurring principally in the rapidly expanding Barnett play in north central Texas, the Devonian Antrim play in Michigan, the Devonian shales of the Appalachian Basin, and smaller pockets in the Illinois and San Juan Basins. The Newark East field near Fort Worth, Texas, producing from the Barnett, is among the largest US gas fields.

Gas shales are self-sourcing, organic-rich reservoirs requiring careful stimulation to produce. Completions utilize a new "light sand frac," horizontal drilling, and the refracturing of previously completed wells. The presence of natural fracturing in the reservoir is a major aid to economic production.

The Barnett is a relatively deep, overpressured, Mississippian age, fractured shale. Drilling and completion technology have evolved with more horizontal wells using water and foam with a small amount of propant. The play is expanding rapidly to the south into Tarrant and Johnson counties and west of Fort Worth, with production expected to continue to increase from 0.40 Bcf per day in 2000 to 0.86 Bcf per day in 2004 and 1.15 Bcf per day in 2012.

The Lewis Shale in the San Juan Basin, while not treated as standalone target, is a secondary target with the surrounding conventional reservoirs and is a solid contributor to production.

Production from the Antrim shale in Michigan has slowly declined from 0.5 Bcf per day around 2000 to 0.4 Bcf per day in 2004, even though some drilling is still occurring. Production from the Devonian shale in the Appalachian Basin will continue to increase slowly from 0.3 Bcf per day in 2000.

Future shale gas production is projected to grow from 1.6 Bcf per day in 2004 to 2.4 Bcf per day in 2012, led by the existing plays but also by other evolving gas shales that have not yet been fully assessed. Some examples include the Fayetteville shale in Arkansas and a Barnett shale lookalike in the Palo Duro Basin in the Texas Panhandle.

UNCONVENTIONAL GAS—COAL SEAM METHANE

A major segment of unconventional gas is CSM, which became the major component in the San Juan Basin in the early 1990s (see Table 5). CSM is also the dominant gas in the Black Warrior Basin of Alabama. The most recent new significant area of CSM production is the Powder River Basin of Wyoming, whose development is currently stalled by environmental concerns and slow drilling permit approvals.*

US CSM capacity increased from 3.96 Bcf per day in 2000 to 4.83 Bcf per day in 2004 and is projected to reach 5.56 Bcf per day in 2012. The growth in CSM is moderated by a gradual decline in the San Juan Basin. Most of the US CSM is produced in the Rockies; however, capacity in this area will remain at around 4.0 Bcf per day to 2012 as slowly declining San

*Coal seam methane is also known as coalbed methane.

Table 5

North American Coal Seam Methane Capacity

United States Lower 48	Recoverable Gas (Tcf)	Average Well Depth (feet)	Capacity Outlook (Bcf per day) 2000	2002	2003	2004	2005	2006	2007	2010	2012
San Juan	10.0	2,600	2.70	2.52	2.51	2.52	2.48	2.43	2.39	2.20	2.05
Powder River*	20.0	700–1,500	0.41	0.91	0.95	0.91	0.95	1.00	1.10	1.30	1.40
Green River**	10.0	650–6,000	—	—	—	0.01	0.01	0.02	0.03	0.05	0.07
Raton	3.5	1,500	0.10	0.20	0.25	0.27	0.30	0.32	0.34	0.35	0.32
Uinta	5.5	3,500	0.20	0.28	0.28	0.25	0.23	0.22	0.21	0.19	0.17
Black Warrior	1.2	1,800	0.27	0.32	0.33	0.33	0.33	0.32	0.31	0.28	0.26
Arkoma/Anadarko			0.04	0.07	0.11	0.15	0.19	0.22	0.25	0.30	0.32
Others***	2.0	—	0.10	0.12	0.18	0.22	0.26	0.30	0.35	0.50	0.70
Virginia			0.14	0.16	0.17	0.17	0.18	0.18	0.18	0.18	0.17
Subtotal			**3.96**	**4.58**	**4.78**	**4.83**	**4.93**	**5.01**	**5.16**	**5.35**	**5.46**
Alaska	—	—	—	—	—	—	—	—	—	0.05	0.10
Total US	—	—	**3.96**	**4.58**	**4.78**	**4.83**	**4.93**	**5.01**	**5.16**	**5.40**	**5.56**
Canada	50.0	2,000–3,000	—	—	0.04	0.09	0.20	0.35	0.50	1.10	1.25
Total North America			**3.96**	**4.58**	**4.82**	**4.92**	**5.13**	**5.36**	**5.66**	**6.50**	**6.81**

Source: Cambridge Energy Research Associates.
*Includes Montana.
**Includes Washakie, Hanna, Sand Wash, and Great Divide Basins.
***Includes Appalachian, Forest City, Illinois, Piceance Basins, and Southeast Kansas.
Updated April 2005.

Juan and Uinta Basin production is offset by expected increases in the Powder River, the Green River, and the Raton Basins. The decline in the San Juan Basin has been reduced by well reentry, new technology, and infill drilling resulting from well downspacing. The Anadarko and Arkoma Basins of Oklahoma are also the scene of current active CSM development.

The ultimate potential of the Powder River Basin remains a wild card in the CSM outlook. Increasing production from the Big George coal seam is critical in offsetting production from the already-declining Wyodak coals. Recent well performance data on Big George wells show low decline rates, which will be favorable to the outlook if sustained. However, Big George coal wells produce more water per thousand cubic feet (Mcf) than other Powder River CSM wells, potentially intensifying environmental concerns over water disposal.

It is expected that CSM will continue to be developed from many of the shallow coal fields in the Appalachians, the Forest City and Illinois Basins, southeast Kansas, and the low-ranked coals along the Gulf Coast. In addition, considerable CSM potential exists in Alaska. However, required changes in shallow-gas leasing procedures have currently stalled activity.

The production profile for CSM wells is similar to that for other unconventional gases except for the timing of initial peak output, which depends on the length of the dewatering process prior to peak production. Some CSM plays, such as the Horseshoe Canyon coals in Alberta, are dry, allowing gas production to ramp up quickly.

CSM in Canada has begun to ramp up quite rapidly from initial production of 0.04 Bcf per day in 2003 to a projected 0.20 Bcf per day in 2005, reaching 1.25 Bcf per day in 2012. The early ramp-up is occurring from the dry Horseshoe Canyon coals in south central Alberta. Production from the deeper, wet Manville coals is expected to provide much of the growth toward 2010.*

THE ROLE OF THE GULF OF MEXICO: THE MAJOR DETERMINANT OF FUTURE US GAS CAPACITY

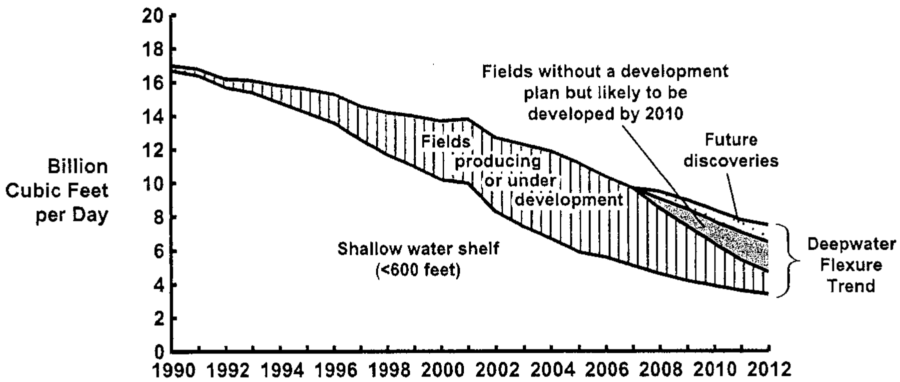
Capacity in the Texas/Louisiana portion of the Gulf of Mexico is projected to decline by 4.4 Bcf per day, from 11.9 Bcf per day in 2004 to 7.5 Bcf per day in 2012, reflecting the peaking of the deep water in 2005 and subsequent decline (with the exception of 2008) through 2012 and beyond (see Figure 8). This is an increase in the expected decline in the Gulf of Mexico by 0.8–1.0 Bcf per day toward the end of the decade compared with our previous outlook.

The Gulf of Mexico continues to experience increasing aggregate decline rates due to the projected early peaking of the deep water, with the exception of a single year, 2008, in response to the development of a series of eight nonassociated gas discoveries in the eastern Gulf (see Figure 9). The deepwater portion of the Gulf has turned disappointing because

*See the CERA Private Report *The Giant Awakens—Coalbed Methane in Canada.*

Figure 8

US Gulf of Mexico* Wet Gas Productive Capacity Outlook



Gulf of Mexico Gas Productive Capacity
(Bcf per day)

	1990	1995	1997	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2010	2012
Shelf	16.7	14.2	12.6	11.0	10.2	10.0	8.3	7.4	6.7	5.9	5.6	5.1	4.6	3.9	3.4
Flexure Trend	0.3	1.4	2.0	3.0	3.5	3.8	4.4	4.9	5.2	5.3	4.8	4.6	4.9	4.5	4.1
Total Gulf	**17.0**	**15.6**	**14.6**	**14.0**	**13.7**	**13.8**	**12.7**	**12.3**	**11.9**	**11.2**	**10.4**	**9.7**	**9.5**	**8.4**	**7.5**

Source: Cambridge Energy Research Associates.
*Includes Louisiana and Texas only.
Updated April 2005
10530-4

of the recent lack of nonassociated gas discoveries, slow company sanctioning of field development, the probable lack of associated gas in the recent spate of large ultradeepwater Eocene oil discoveries stretching from Texas to south of the Mississippi Delta, more rapid declines experienced in some fields, poor discovery appraisal results, and the removal of some earlier discoveries from expected development until at least after 2010 for economic reasons.* Recent major company mergers and acquisitions tend also to delay development decisions.

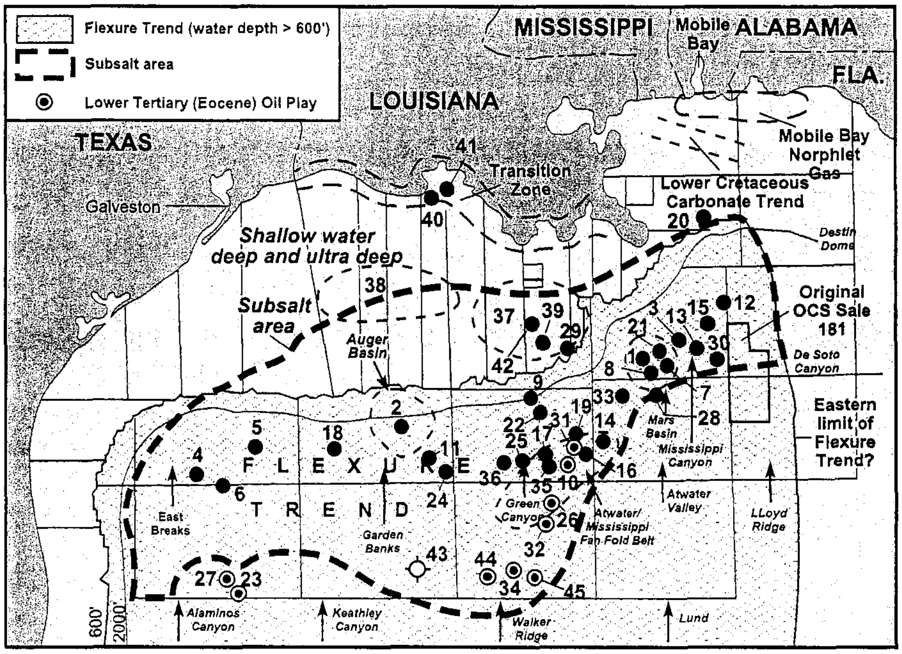
In the deep water (Flexure Trend), most of the larger recent nonassociated gas discoveries are in production: the Canyon Express, Nakika, and the Nansen/Boomvang/Falcon group of fields. In the next few years the last of the larger associated gas fields will come into production: Thunderhorse, Mad Dog, Holstein, Atlantis, K2, and K2 North.

Capacity in the deepwater Gulf of Mexico is projected to peak at 5.31 Bcf per day in 2004–05 before declining to 4.06 Bcf per day, with the exception of 2008, when the Independence platform, receiving gas from eight nearby discoveries, is expected to ramp up to 0.85 Bcf per day, interrupting the decline in deepwater production for one year (see Figure 10).

*See the CERA Private Report *Worldwide Liquids Capacity Outlook to 2010—Tight Supply or Excess of Riches?*

Figure 9

US Gulf of Mexico Flexure Trend and Associated Plays



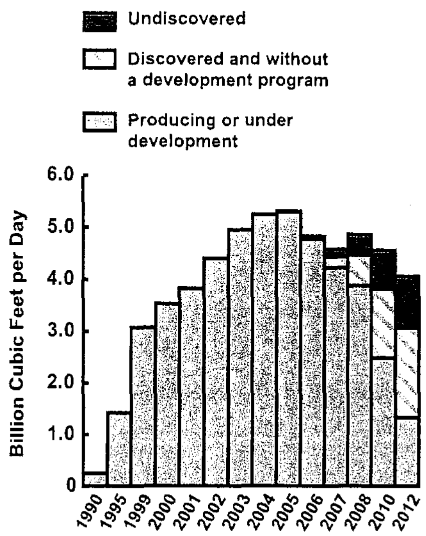
1. Mars Field
2. Auger Field
3. Mensa gas field – 5,412' WD
4. Diana Field
5. East Breaks 602,642-3, Nansen and Boomvang Fields
6. Hoover, Madison, Marshall Fields
7. Ursa – third largest oil and gas field
8. Mirage/Morgus discoveries
9. Brutus Field
10. Mad Dog development & deep prospect
11. Magnolia/Entrada development
12. Aconcagua Field
13. Thunder Horse, largest oil discovery, North Thunder Horse
14. Neptune discovery*
15. Nakika Field
16. Atlantis development*
17. Holstein Field
18. Gunnison Field
19. K2*/Timon/Marco Polo, K2 North complex
20. Canyon Station
21. Princess development
22. Front Runner Field
23. Trident Discovery–Perdido Fold Belt
24. Red Hawk Field
25. Tahiti discovery
26. Cascade discovery
27. Great White discovery
28. Champlain discovery*
29. Tarantula subsalt development
30. E. Gulf discoveries – Independence Hub
31. Shenzi discovery & deep prospect
32. Chinook discovery
33. Sturgis discovery
34. Saint Malo discovery
35. Puma discovery
36. Constellation development
37. Treasure Island–ultra deep shelf area
38. Treasure Bay–ultra deep shelf area
39. Shark ultra deep dry hole
40. JB Mountain field
41. Mound Point field
42. Blackbeard well 32,000 foot prospect
43. Sardinia dry hole (thick Eocene sand)
44. Jack discovery
45. Das Bump prospect

Source: Cambridge Energy Research Associates.
*Recent significant reserve increase.
Updated May 2005
40916-5

Capacity on the shallow-water shelf is expected to continue its decline through 2012 and beyond. Since the 2001 peak year of drilling activity with 158 active rigs, activity on the shelf has been lower by 30 to 70 rigs, thus significantly reducing the availability of new production to offset declining existing production. High decline rates in the small discoveries will perpetuate the decline on the shelf.

Figure 10

Components of Louisiana and Texas Flexure Trend Gas Productive Capacity
(water depth >600 feet)



Wet Gas Capacity Buildup in the Flexure Trend
(Bcf per day)

	1995	2000	2003	2004	2005	2006	2007	2008	2010	2012
Discovered Fields										
Fields producing or under development										
Louisiana	1.42	3.44	4.22	4.45	4.59	4.25	3.85	3.65	2.39	1.30
Texas	—	0.09	0.73	0.80	0.71	0.52	0.37	0.23	0.09	0.03
Total	**1.42**	**3.53**	**4.95**	**5.25**	**5.30**	**4.77**	**4.22**	**3.88**	**2.48**	**1.33**
Fields without a development plan but likely to be developed										
Louisiana	—	—	—	—	0.01	0.06	0.21	0.58	1.26	1.13
Texas	—	—	—	—	—	—	—	—	0.07	0.60
Total	—	—	—	—	**0.01**	**0.06**	**0.21**	**0.58**	**1.33**	**1.73**
Total Discovered Fields	**1.42**	**3.53**	**4.95**	**5.25**	**5.31**	**4.83**	**4.43**	**4.46**	**3.81**	**3.06**
Undiscovered Fields*	—	—	—	—	—	—	**0.15**	**0.40**	**0.75**	**1.00**
Total Flexure Trend	**1.42**	**3.53**	**4.95**	**5.25**	**5.31**	**4.83**	**4.58**	**4.86**	**4.56**	**4.06**
Memo: Discovered fields unlikely to be developed before 2010	—	—	—	—	—	—	0.09	0.54	1.10	—

Source: Cambridge Energy Research Associates.
*Includes Eastern Gulf.
Updated April 2005
40916-1

A secondary play on the shelf—the deep shelf gas play—is rapidly moving forward. Although the play has long been known to exist, advances in the interpretation of 3D seismic followed by several large discoveries have reignited interest in the deep structures characteristic of this play. After having abandoned this area to pursue deepwater prospects, supermajors, other large companies, and large independents have returned to the shelf and amassed large acreage positions in recent lease sales and in joint ventures with existing smaller company leaseholders.

The deep gas play, below 15,000 feet, has captured much of the interest on the shallow-water shelf, with numerous wells being drilled and drilling companies upgrading and building new rigs to meet the demand for this deep drilling. Companies are pursuing targets of 30 to 200 Bcf compared with conventional shelf targets above 15,000 feet of less than 10 Bcf. The shift to the deep play is a major reason for the slow pickup in shallow-water jackup activity, owing to the limited availability of rigs capable of deep drilling much below 15,000 feet. Deep drilling is characterized by high temperatures and pressures, longer driling time, and high drilling costs.

Recent deep shelf discoveries include the JB Mountain and Mound Point fields, the Tarantula subsalt field, and the Deep Tern and Hurricane Upthrown discoveries. Many of the wells on the deep shelf produce between 10 and 30 million cubic feet (MMcf) per day. The 20 productive wells drilled in 2004 could lead to production of 0.3 to 0.4 Bcf per day within a year.

Production from the deep shelf has increased only slowly from 0.8 Bcf per day in 1995 to 1.1 Bcf per day in the late 1990s and early 2000s and to 1.45 Bcf per day in 2002. Due to the rapid decline in existing wells, growth in production is likely to remain labored, at least through 2010, and will do little to slow the decline on the shelf.

A new target on the shelf is the ultradeep shelf play below 25,000 feet for lower Miocene to Cretaceous reservoirs and large structures with reserves possibly exceeding 1–5 Tcf. Several unsuccessful wells have been drilled, but the primary result so far has been successful penetration below 25,000 feet. Currently the Blackbeard West wildcat is targeting a large structure at 32,000 feet. Several other wells are drilling toward 25,000 feet. Any significant production from the ultradeep shelf is not likely until after 2010, as production technology will have to be perfected.

REGIONAL HIGHLIGHTS

A discussion of the important plays in the individual region follows.

Gulf Coast

Stretching from South Texas across Louisiana, this area has significant potential for discovery. Deep (below 12,000 feet), high-capacity, high-cost wells targeting the Wilcox, Yegua, and Frio formations are common, especially in South Texas and south Louisiana. Capacity is projected to increase by 0.67 Bcf per day, from 13.20 Bcf per day in 2004 to 14.11 Bcf per day in 2010, before declining to 13.87 Bcf per day in 2012 (see Table 6). The main activity involves reworking wells in existing fields and drilling to deeper zones in existing fields.

The Gulf Coast region is also the location of two important tight gas plays: the Cotton Valley/Bossier Sand in Texas RRC-5 and 6 in East Texas and the Cotton Valley in north Louisiana. Production in these areas is projected to increase by 0.5 Bcf per day, from 4.37 Bcf per day in 2004 to 4.87 Bcf per day in 2012. Production in South Texas RRC-4 and south Louisiana is currently declining in response to the slow recovery of drilling from the 2002 lows. These areas are considered deep, expensive wildcat plays, and companies have redirected their emphasis to low-risk, shallower, unconventional gas drilling. However, recently drilling activity in these areas has increased closer to the 2001 peak levels. CERA's outlook reflects this recent increase in activity, which could lead to a moderate increase in capacity from these highly prospective areas from 5.32 Bcf per day in 2004 to 5.70 Bcf per day in 2012.

Table 6

Wet Gas Capacity Outlook by Region

(Bcf per day)

	1995	1997	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Gulf of Mexico	**16.62**	**15.76**	**15.01**	**14.64**	**14.69**	**13.57**	**13.13**	**12.55**	**11.80**	**11.04**	**10.29**	**10.05**	**9.45**	**8.87**	**8.18**	**7.85**
Alabama Offshore	1.00	1.14	1.04	0.94	0.89	0.84	0.79	0.70	0.64	0.59	0.54	0.50	0.45	0.42	0.38	0.35
Louisiana Offshore	11.92	11.33	11.43	11.26	11.33	10.48	9.75	9.29	8.81	8.30	7.80	7.80	7.40	7.00	6.40	5.90
Texas Offshore	3.70	3.29	2.54	2.44	2.47	2.25	2.59	2.56	2.35	2.15	1.95	1.75	1.60	1.45	1.40	1.60
Subtotal TX/LA Offshore	*15.62*	*14.62*	*13.97*	*13.70*	*13.80*	*12.73*	*12.34*	*11.85*	*11.16*	*10.45*	*9.75*	*9.55*	*9.00*	*8.45*	*7.80*	*7.50*
Gulf Coast	**13.25**	**14.01**	**13.34**	**13.68**	**13.76**	**13.08**	**13.22**	**13.20**	**13.33**	**13.57**	**13.80**	**14.01**	**14.09**	**14.11**	**14.04**	**13.87**
Texas District 1	0.25	0.32	0.31	0.28	0.28	0.25	0.26	0.28	0.27	0.27	0.27	0.28	0.28	0.28	0.27	0.26
Texas District 2	0.63	0.70	0.84	0.87	0.85	0.76	0.75	0.76	0.75	0.74	0.73	0.71	0.70	0.69	0.68	0.67
Texas District 3	2.30	2.50	2.21	2.35	1.98	1.63	1.60	1.62	1.64	1.66	1.68	1.70	1.70	1.65	1.60	1.55
Texas District 4	3.32	3.60	3.30	3.46	3.66	3.74	3.63	3.32	3.25	3.30	3.40	3.50	3.50	3.50	3.45	3.35
Texas District 5	0.48	0.58	0.60	0.75	0.92	1.02	1.27	1.42	1.48	1.55	1.58	1.60	1.62	1.64	1.65	1.65
Texas District 6	1.62	1.51	1.53	1.58	1.62	1.55	1.58	1.69	1.75	1.80	1.83	1.85	1.87	1.89	1.90	1.90
Louisiana Onshore-South	2.82	2.70	2.61	2.56	2.56	2.26	2.12	2.00	2.02	2.05	2.10	2.15	2.20	2.25	2.30	2.35
Louisiana Onshore-North	1.01	1.25	1.13	1.10	1.12	1.10	1.18	1.26	1.30	1.32	1.33	1.34	1.35	1.35	1.35	1.32
Mississippi	0.29	0.32	0.30	0.24	0.30	0.31	0.37	0.40	0.43	0.45	0.46	0.47	0.48	0.49	0.50	0.50
Alabama Onshore	0.51	0.51	0.49	0.47	0.45	0.45	0.45	0.44	0.43	0.42	0.41	0.40	0.38	0.36	0.34	0.32
Florida	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Mid-Continent	**9.81**	**9.13**	**7.92**	**7.96**	**7.92**	**7.84**	**7.80**	**7.85**	**7.91**	**8.01**	**8.12**	**8.14**	**8.20**	**8.26**	**8.25**	**8.20**
Texas District 7B	0.20	0.19	0.16	0.16	0.16	0.16	0.15	0.14	0.15	0.16	0.17	0.18	0.19	0.20	0.21	0.20
Texas District 9	0.29	0.30	0.31	0.40	0.51	0.67	0.80	0.86	0.88	0.93	0.98	1.03	1.08	1.13	1.14	1.15
Texas District 10	1.28	1.20	1.09	1.08	1.04	0.98	0.94	0.97	0.99	1.01	1.03	1.05	1.07	1.09	1.10	1.10
Kansas	2.19	1.85	1.52	1.44	1.32	1.25	1.15	1.10	1.05	1.00	0.99	0.90	0.85	0.80	0.75	0.70
Oklahoma	5.31	5.00	4.37	4.41	4.43	4.33	4.30	4.30	4.35	4.40	4.43	4.45	4.47	4.49	4.50	4.50
Arkansas	0.54	0.59	0.47	0.47	0.46	0.45	0.46	0.48	0.49	0.51	0.52	0.53	0.54	0.55	0.55	0.55

Table 6

Wet Gas Capacity Outlook by Region (continued)

(Bcf per day)

	1995	1997	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Rocky Mountains	**3.98**	**4.06**	**4.63**	**5.08**	**6.02**	**6.51**	**7.04**	**7.12**	**7.50**	**7.90**	**8.28**	**8.63**	**8.94**	**9.19**	**9.41**	**9.60**
Arizona	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Northern Colorado (2)	0.80	0.82	0.87	0.94	1.11	1.37	1.54	1.61	1.67	1.75	1.82	1.87	1.90	1.90	1.90	1.90
Montana	0.16	0.17	0.17	0.19	0.22	0.24	0.24	0.26	0.28	0.30	0.32	0.34	0.35	0.35	0.33	0.31
North Dakota	0.14	0.15	0.15	0.15	0.16	0.16	0.15	0.15	0.16	0.17	0.18	0.18	0.18	0.18	0.17	0.16
Utah	0.77	0.77	0.73	0.74	0.78	0.75	0.73	0.74	0.78	0.82	0.85	0.88	0.90	0.90	0.90	0.87
Wyoming	2.10	2.14	2.70	3.05	3.74	3.98	4.37	4.35	4.60	4.85	5.10	5.35	5.60	5.85	6.10	6.35
Permian	**5.21**	**5.02**	**4.69**	**4.92**	**4.97**	**4.82**	**4.76**	**4.62**	**4.55**	**4.49**	**4.42**	**4.33**	**4.24**	**4.15**	**4.03**	**3.91**
Southeast New Mexico	1.51	1.43	1.32	1.53	1.65	1.61	1.57	1.57	1.59	1.59	1.57	1.53	1.49	1.45	1.40	1.35
Texas District 7C	1.05	1.08	0.92	0.91	0.92	0.91	0.95	0.86	0.82	0.78	0.76	0.74	0.72	0.70	0.68	0.66
Texas District 8	2.07	1.93	1.86	1.85	1.75	1.66	1.58	1.51	1.44	1.40	1.35	1.30	1.25	1.20	1.15	1.10
Texas District 8A	0.58	0.58	0.59	0.63	0.65	0.64	0.66	0.68	0.70	0.72	0.74	0.76	0.78	0.80	0.80	0.80
San Juan	**3.77**	**3.90**	**4.18**	**4.21**	**4.11**	**4.06**	**4.05**	**4.05**	**4.02**	**3.96**	**3.90**	**3.84**	**3.78**	**3.72**	**3.66**	**3.60**
Southern Colorado	0.73	0.97	1.11	1.11	1.15	1.23	1.27	1.26	1.24	1.21	1.18	1.15	1.12	1.09	1.06	1.03
Northwest New Mexico	3.04	2.93	3.07	3.10	2.96	2.83	2.78	2.79	2.78	2.75	2.72	2.69	2.66	2.63	2.60	2.57
Eastern US	**2.51**	**2.33**	**2.34**	**2.35**	**2.37**	**2.41**	**2.39**	**2.45**	**2.57**	**2.69**	**2.79**	**2.85**	**2.85**	**2.86**	**2.79**	**2.71**
Michigan	0.84	0.80	0.70	0.67	0.64	0.60	0.56	0.54	0.51	0.49	0.47	0.45	0.43	0.41	0.39	0.37
Kentucky	0.22	0.23	0.21	0.22	0.22	0.24	0.25	0.27	0.30	0.32	0.34	0.36	0.38	0.40	0.40	0.40
Ohio	0.36	0.33	0.30	0.27	0.27	0.27	0.26	0.26	0.26	0.26	0.25	0.25	0.24	0.24	0.23	0.23
New York	0.06	0.05	0.05	0.05	0.08	0.10	0.11	0.15	0.20	0.24	0.28	0.30	0.30	0.30	0.29	0.28
Pennsylvania	0.32	0.23	0.37	0.40	0.42	0.43	0.44	0.43	0.45	0.47	0.49	0.50	0.50	0.50	0.49	0.47
Virginia	0.15	0.17	0.19	0.20	0.20	0.21	0.22	0.22	0.23	0.25	0.26	0.25	0.23	0.21	0.20	0.19
West Virginia	0.54	0.50	0.50	0.52	0.52	0.53	0.51	0.52	0.54	0.56	0.58	0.60	0.61	0.62	0.60	0.57
Other States (1)	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.06	0.08	0.10	0.12	0.14	0.16	0.18	0.19	0.20

Table 6

Wet Gas Capacity Outlook by Region (continued)

(Bcf per day)

	1995	1997	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
West Coast	**0.84**	**0.84**	**1.07**	**1.04**	**1.04**	**1.00**	**0.93**	**0.87**	**0.84**	**0.81**	**0.78**	**0.75**	**0.72**	**0.69**	**0.65**	**0.62**
California	0.83	0.83	1.06	1.03	1.03	0.99	0.92	0.86	0.83	0.80	0.77	0.74	0.71	0.68	0.65	0.62
Oregon	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Total Lower 48	**55.99**	**55.05**	**53.18**	**53.88**	**54.88**	**53.29**	**53.32**	**52.71**	**52.52**	**52.47**	**52.38**	**52.60**	**52.27**	**51.85**	**51.01**	**50.36**
Alaska	**1.40**	**1.40**	**1.40**	**1.40**	**1.40**	**1.40**	**1.35**	**1.30**	**1.25**	**1.20**	**1.15**	**1.10**	**1.05**	**1.00**	**0.95**	**0.90**
North																
South	1.40	1.40	1.40	1.40	1.40	1.40	1.35	1.30	1.25	1.20	1.15	1.10	1.05	1.00	0.95	0.90
Total US	**57.39**	**56.45**	**54.58**	**55.28**	**56.28**	**54.69**	**54.67**	**54.01**	**53.77**	**53.67**	**53.53**	**53.70**	**53.32**	**52.85**	**51.96**	**51.26**
Total US, Dry (3)	**54.75**	**53.85**	**52.07**	**52.74**	**53.69**	**52.17**	**52.20**	**51.53**	**51.30**	**51.20**	**51.07**	**51.23**	**50.87**	**50.42**	**50.42**	**50.42**

Source: Cambridge Energy Research Associates.
1 Includes Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, South Dakota, and Tennessee.
2 Includes New Mexico's portion of the Raton Basin.
3 Dry/wet factor 95.4 percent.
Updated April 2005.

Rockies

The Rockies (excluding the San Juan Basin) are expected to provide the greatest offset to the ongoing significant production decline in the Gulf of Mexico. Capacity is projected to increase 2.48 Bcf per day, from 7.12 Bcf per day in 2004 to 9.60 Bcf per day in 2012, representing nearly 35 percent growth from this important region. Wyoming will show the largest growth, adding 2.0 Bcf per day, followed by northern Colorado, adding 0.29 Bcf per day. Record drilling activity in the Rockies supports the projected growth in capacity. More than three quarters of the resource base in the Rockies is unconventional gas. Numerous plays occur in Wyoming, including the tight sands in the Jonah and Pinedale fields and CSM production in the Powder River and other basins in the southern portion of the state.

Production in both the Jonah and Pinedale fields in Wyoming is projected to reach 1.0 Bcf per day within the next five years. Further downspacing in the Jonah field has been held up pending approval of the infill program. CSM production in the Powder River Basin actually declined in 2004 due to poorer-than-expected performance in the shallower Wyodak coals and the slow well permitting process. Eventual development of the deeper Big George coals should reverse this decline and add to production. Record production in the Madden field in the Wind River Basin largely offset these declines in Wyoming in 2004. Developments in the Washakie Basin are also contributing to the growth in Wyoming.

Northern Colorado has three important plays. Production from tight sands in the Piceance Basin should reach 1.0 Bcf per day by 2012, the Wattenburg field in the Denver Julesburg Basin should at least maintain current capacity levels, and CSM in the Raton Basin is expected to increase. Production in Utah is projected to increase slightly in response to infill drilling programs in the Greater Natural Buttes field and to associated gas from the recent significant Covenant oil discovery on the Central Utah Overthrust Belt.

Permian Basin

Capacity in the Permian Basin is projected to decline slowly by 0.71 Bcf per day, from 4.62 Bcf per day in 2004 to 3.91 Bcf per day in 2012. The continuous decline since 2000 has been mitigated by the Montoya-Devonian horizontal play, the Morrow play in southeast New Mexico, tight sand drilling in the Canyon Sand play in the Ozona field area, and other pockets of infill and tight sand activity.

San Juan Basin

Capacity in the San Juan Basin (including southwest Colorado) is projected to slowly decline by 0.45 Bcf per day, from 4.05 Bcf per day in 2004 to 3.60 Bcf per day in 2012. Production in the San Juan Basin is 60 percent CSM. The downsizing of well spacing in the Fruitland coals has reduced the previously projected decline. "Conventional" gas production is largely unconventional tight sand gas, and even though numerous undrilled locations exist due to downspacing, this production has remained in a narrow band for the past five years.

Mid-Continent

The Mid-Continent area includes three important areas of increasing capacity: the Barnett shale gas play in north central Texas, the Granite Wash play in the Texas Panhandle, and the Anadarko/Arkoma Basins in Oklahoma. Capacity in the Mid-Continent region is projected to increase slightly from 7.85 Bcf per day in 2004 to 8.26 Bcf per day in 2010 before declining slightly to 8.20 Bcf per day in 2012.

The core Barnett shale area is in RRC-9 and is projected to continue to increase from 0.86 Bcf per day in 2004 to 1.15 Bcf per day in 2012. The Barnett play is expanding into RRC-5 and RRC-7B to the south and west of Fort Worth, Texas, with companies actively acquiring acreage and drilling horizontal wells.

Capacity in Oklahoma is projected to increase slightly from 4.30 Bcf per day in 2005 to 4.5 Bcf per day in 2012. This increase, reflecting the recent high rate of drilling, contrasts with the decline evident since the late 1990s and the reversal of CERA's previous outlooks for a continuing decline. In the Anadarko Basin production from the shallow portion (less than 15,000 feet) is expected to continue to decline; however, deep production (at greater than 15,000 feet) and CSM from the Arkoma Basin are expected to increase.

Capacity in Arkansas is projected to increase moderately assuming the Fayetteville gas shale play materializes as expected. Capacity in the Texas Panhandle (RRC-10) has reversed a recent decline and is projected to increase slowly from 0.97 Bcf per day in 2004 to 1.10 Bcf per day in 2012 from the tight Granite Wash reservoir in the Buffalo Wallow field. Rig count in this area has soared to 63 rigs from 30 rigs in late 2003.

Capacity in Kansas is expected to continue to decline from 1.1 Bcf per day in 2004 to 0.7 Bcf per day in 2012 as the Hugoton field continues to decline.

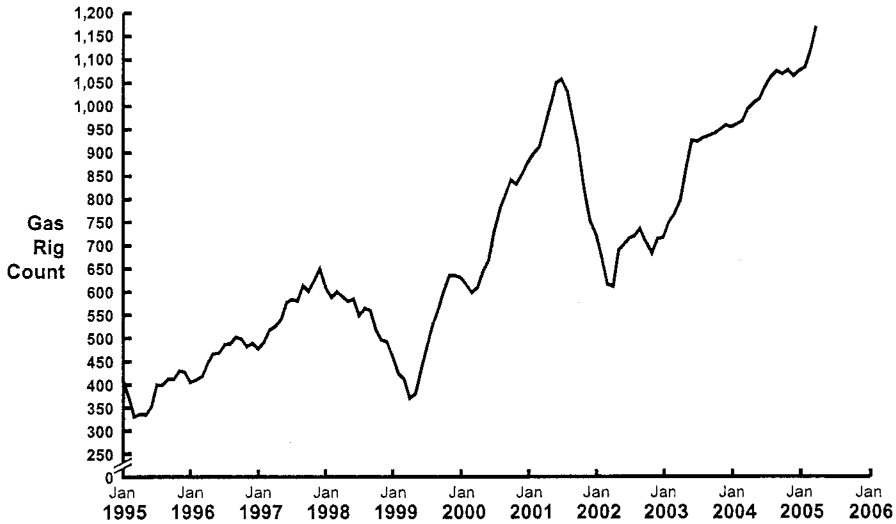
Eastern United States

Capacity in the eastern United States (largely Michigan, West Virginia, and Pennsylvania) is projected to show slight growth, from 2.45 Bcf per day in 2004 to 2.86 Bcf per day in 2010, with a slight decline to 2.71 Bcf in 2012. New York, with the deep Trenton–Black River play, and West Virginia lead the growth, offset somewhat by the declining Antrim shale production in Michigan.

GAS-RELATED DRILLING

Since the recent low point of 591 rigs reached in April 2002, activity recovered rapidly into mid-2003 before embarking on a slower increase to record levels above the 2001 high of 1,068 rigs in the fall of 2004. After hovering at 1,090 rigs until early March 2005, rig activity has jumped to 1,175 rigs in mid-April 2005, with large increases in Wyoming, South Louisiana, East Texas, and New Mexico (see Figure 11).

Figure 11
US Gas-related Drilling



Source: Baker Hughes Inc.
Note: A secondary peak of 1,068 rigs was attained in July 2001.
Updated May 2005
40916-2

Continuing the lackluster recovery from the 2002 low pace of rig activity, activity in the Gulf of Mexico is hovering at around 90 rigs, 68 rigs below the 2001 peak of 158 rigs and only a few rigs above the 2002 low point. Most of the drop in activity has occurred in the shallow-water shelf, thus contributing to its rapid decline in production. Also between 2001 and October 2004, 47 jackups have left the Gulf.

There is a close coincidence between the leading areas of rig activity and areas with strong projected growth in supply. All of these areas involve unconventional gas, mostly tight sands and some shales (see Table 7). Rig activity in these areas is close to the 2002–05 peaks and in most cases is substantially above the record highs of 2001.

The current rig situation in many areas onshore involves long delays in obtaining a rig as most drilling companies are close to full rig utilization. Compounding the rig availability situation is the lack of manpower for rig crews and for service companies that are falling behind in meeting the soaring demand for well fracing. Evidence of the tight market are the deals between producers and drilling companies to utilize newly built rigs as they become available. Some drilling companies are now building new rigs, and this trend should accelerate as the duration of the drilling boom becomes more obvious. (The shallow CSM wells in the Powder River Basin are drilled with truck-mounted rigs, which are excluded from the active rig count.)

Table 7

Active Rig Count—Leading Areas of Current Activity

(includes oil and gas wells)

	1997–98 Weekly High	1999 Weekly Low	2001 High	2002–05 Low	2002–05 High	Latest Count (April 15, 2005)
Rockies						
Colorado	19	7	41	22	73	71
Montana	16	4	13	5	25	26
Wyoming	49	18	66	29	87	76
Total	**84**	**29**	**120**	**56**	**185**	**173**
Texas	396	171	572	251	594	594
South and East						
RRC 5 (Bossier)	31	9	73	28	73	70
RRC 6 (E. Texas)	45	15	58	21	92	92
RRC 9 (Barnett)	10	4	38	25	49	35
RRC 10 (N. Texas)	31	8	27	6	63	61
North Louisiana	—	—	—	13	49	45
Oklahoma	109	46	160	68	178	153

Source: Baker Hughes Inc.
Updated April 2005.

Memo:						
Gulf of Mexico	141	84	158	86	125	91

Offshore, the movement of jackups out of the region has tightened the market as deep shelf drilling has become the dominant target. Deep and ultradeepwater rigs are mostly contracted with day rates exceeding $270,000. At this time there are only 14 rigs worldwide, consisting of drillships and floaters capable of drilling in 10,000 feet of water, and only an additional 22 rigs that can drill in 8,000 feet of water. Two new 7,500-foot water depth semisubmersible rigs are being delivered this spring. Most of the other current newbuilds are shallow-water jackups capable of drilling deep shelf wells. There are also plans to return several departed deepwater rigs to the Gulf of Mexico.

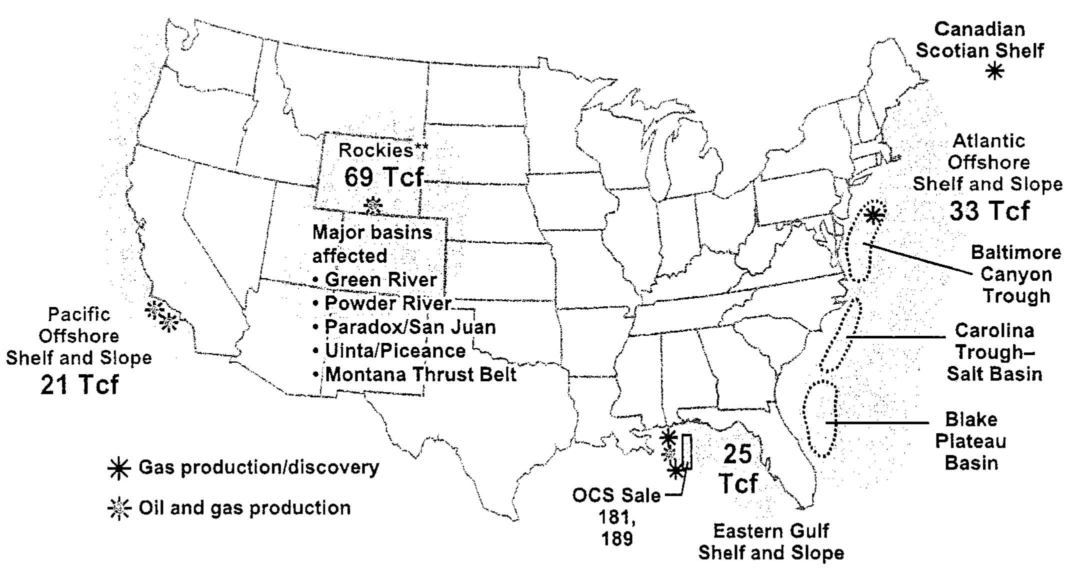
In the deep and ultradeep water, the demand for rigs to continue exploration, appraisal, development, and the test of the large number of leases expiring in the next three years will begin to exceed the supply. This could be a factor in the timing to develop some of the recent ultradeepwater oil discoveries. Numerous large Lower Tertiary oil discoveries have been made recently, inspiring active exploration and appraisal activity along the trend. Since these wells are drilled below 27,000 feet, they require around six months to drill, thus severely limiting the number of wells that can be drilled per year per rig.

ACCESSIBILITY

Increased access to areas with a large potential resource base is critical to the ability to continue to moderate the decline in capacity. US conventional resources offshore that are now off limits are on both coasts and in most of the eastern Gulf of Mexico. These areas have been subject to congressionally imposed drilling moratoria and leasing prohibitions since the early 1980s and currently in effect until 2012—thus preventing industry from exploiting resources that total as much as 79 Tcf (see Figure 12). Even though economic quantities of gas are known to exist in each area, none of this gas is included in the outlook to 2012 owing to CERA's expectation that the intractability of opening these lands pushes their potential production beyond 2012.

Figure 12

US Lower-48 Undiscovered Gas Resources Subject to Access Restrictions*



Source: Cambridge Energy Research Associates/National Petroleum Council.
*148 Tcf are off limits for exploration and development.
**An additional 56 Tcf of the Rockies gas resources are available with restrictions and delays.
Updated April 2005
40916-43

Draft legislation circulating in the US Congress would expand state control over offshore energy development and eliminate the blanket moratoria. Virginia has passed legislation, recently rejected by the governor, seeking to end the federal moratorium off its coast and allow seismic activity by working with the state congressional delegation. States would claim up to half of the revenues depending on their distance from the coast. However, the Carolinas, Florida, and California continue to oppose efforts to reinstate drilling.

This outlook assumes that drilling restrictions onshore, mostly in the Rockies, involving an additional potential resource of 69 Tcf, are not materially eased in the near future. An additional 56 Tcf of reserves are available for exploitation; however, these resources are subject to restrictions and delays. Most of this gas is unconventional and would provide an important extension to the tight sand and CSM plays currently under development. In addition, the Bureau of Land Management well permitting process to drill wells on federal lands has been subject to considerable delays, thus delaying new production. An ongoing effort to streamline procedures has been moving forward. However, without radical revision to the National Environmental Policy Act, requirements for environmental impact statements and delays in oil and gas developments will continue to be an aspect of working in the Rockies. In addition, most of the unconventional gas production requires hydraulic facing, and this can be at odds with the Safe Drinking Water Act. Growing western populations and ongoing conflicts between resource- and recreation-based economies also contribute to the difficulties in developing Rockies resources. Currently the focal points in land access issues in the Rockies are the Jack Morrow subbasin in the Green River Basin and the Roan Plateau in the Piceance Basin. In addition, a number of areas in Montana, Utah, and New Mexico also have prospective lands that are off limits to some degree. This is an important factor since it is the Rockies that are being counted on to play the dominant role in offsetting the decline in the Gulf of Mexico.

CANADIAN DRY GAS OUTLOOK: SLOWLY INCREASING GROWTH ACCELERATES BY 2010

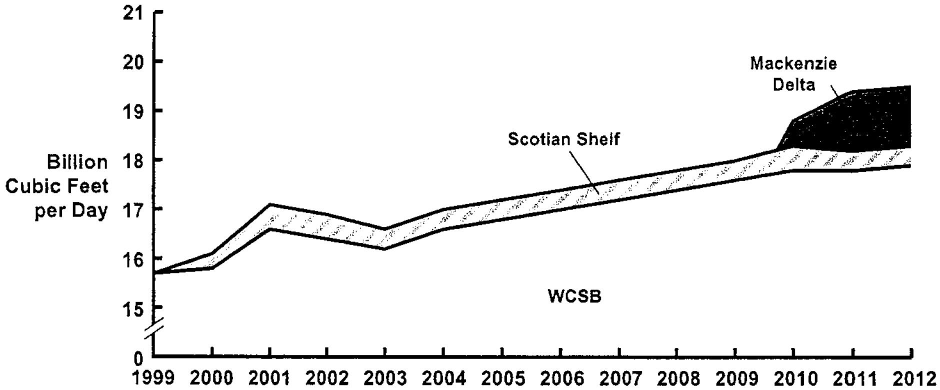
Canadian dry gas capacity is projected to increase slowly from 17.0 Bcf per day in 2004 to 18.0 Bcf per day in 2009 before accelerating to 19.5 Bcf per day in 2012 with production from the Mackenzie Delta (see Figure 13). The peak of 17.1 Bcf per day in 2001 was coincident with the attainment of the 0.5 Bcf per day peak from the Sable Island project in the eastern Canadian offshore and peak production from the Ladyfern field in northeast British Columbia. The decline to the 16.6 Bcf per day low point in 2003 was largely the result of the rapid decline in the Ladyfern field from 0.7 Bcf per day to less than 0.2 Bcf per day by 2003.

Production from the WCSB is projected to increase 1.3 Bcf per day, from 16.6 Bcf per day in 2004 to 17.9 Bcf per day in 2012. Most of the increase is related to unconventional gas—tight sands and carbonates, and CSM—plus consecutive years of record gas-related drilling, which is likely to continue (although the drilling season came to an abrupt early end by early March 2005 due to an early warmup).

Offsetting the rapid decline in the shallow gas in eastern Alberta and southeastern Saskatchewan is a series of plays in the deeper portions of the WCSB (see Figure 14). Among these plays are the Greater Sierra Jean Marie reef play in northeastern British Columbia consisting of tight carbonates and requiring underbalanced horizontal drilling,

Figure 13

Canadian Dry Gas Productive Capacity



Canadian Gas Capacity (Bcf per day)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WCSB	15.7	15.8	16.6	16.4	16.2	16.6	16.8	17.0	17.2	17.4	17.6	17.8	17.8	17.9
Eastern offshore	0.0	0.3	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.4
Mackenzie Delta	–	–	–	–	–	–	–	–	–	–	–	0.5	1.2	1.2
Total	15.7	16.1	17.1	16.9	16.6	17.0	17.2	17.4	17.6	17.8	18.0	18.8	19.4	19.5

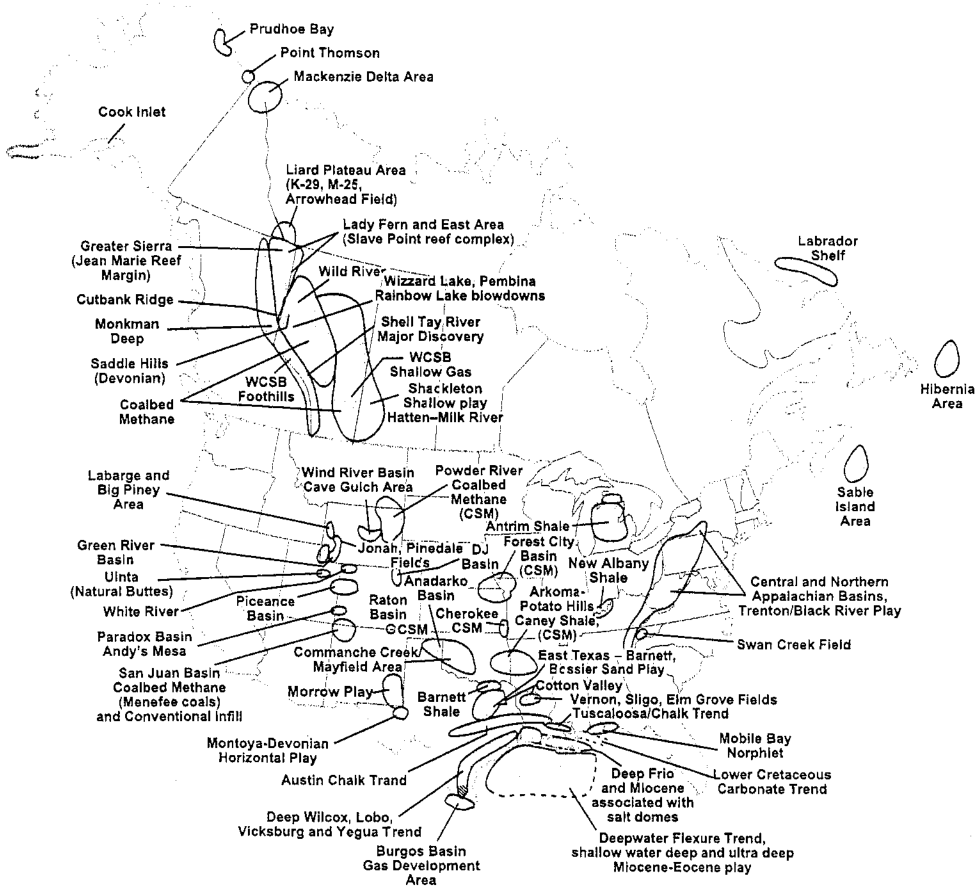
Source: Cambridge Energy Research Associates.
Updated April-1 2005
40916-9

the Cutbank Ridge play, the prolific Monkman Deep Paleozoic play, Saddle Hills Devonian, "blowdowns" in economically depleted oil fields accounting for over 0.2 Bcf per day of production through 2006, and the Pembina Nisku area revival. The Greater Sierra and Cutbank Ridge plays are tight gas unconventional resource plays located in the Deep Basin and are undergoing active development. Shale gas plays in Canada have not yet been exploited, although several shales have considerable potential, including the Nordegg, the Doig Phosphate, the upper Doig, and the Duvernay. In addition, the recent significant discovery, Tay River, in the foothills area could establish a deep productive trend.

A large contributor to the growth of the WCSB is CSM in southern Alberta. After initial production in 2003, Canadian CSM is projected to increase from an average annual production rate of 0.09 Bcf per day in 2004 to 0.5 Bcf per day in 2007 and 1.25 Bcf per day in 2012, assuming the commercial exploitation of the Mannville coals. Initial production has been largely from the dry, low-cost, shallow Horseshoe Canyon/Belly River coals requiring little time to ramp up to average well production of 0.1 to 0.15 MMcf per day, utilizing the existing infrastructure. With time the CSM play will spread to the deeper, water-wet Mannville coals, which, upon dewatering, will be the major source of CSM. Drilling in the CSM play is expected to almost triple in 2005, with 3,000 wells compared with 1,250 wells in 2004. British Columbia also has attractive CSM potential, although environmental concerns have stalled leasing in the coal-rich Elk Valley in the south near the US border.

Figure 14

Major North American Gas Exploration and Development Hot Spots



Source: Cambridge Energy Research Associates.
Updated April 2005
40916-6

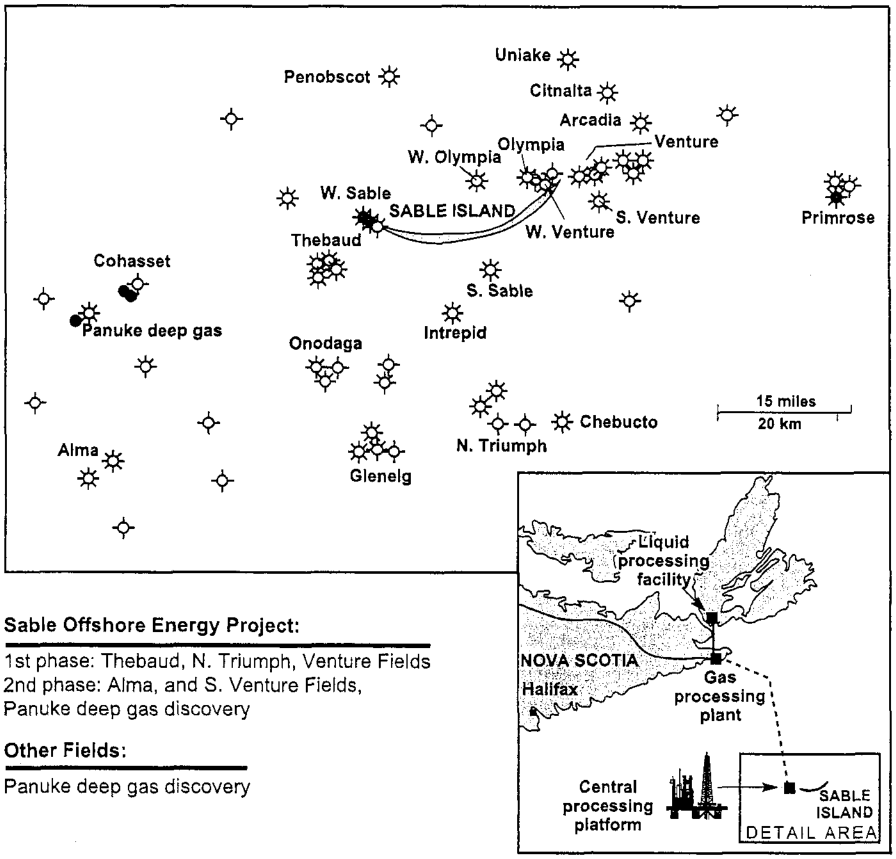
It has been estimated that unconventional gas production in the WCSB is currently around 1.5 Bcf per day. With the emphasis on tight reservoirs in the Deep Basin and the anticipated growth of CSM, unconventional gas in Canada could be close to 4 Bcf per day by 2012.

EASTERN CANADIAN OFFSHORE

The eastern Canadian offshore Sable Island project commenced production in 2000, increasing to a 0.5 Bcf per day peak in 2001 from three initial fields (Thebaud, Venture, and North Triumph) (see Figure 15). However, production from these fields has been declining

Figure 15

Nova Scotia Offshore Significant Discovery Areas



Sable Offshore Energy Project:

1st phase: Thebaud, N. Triumph, Venture Fields
2nd phase: Alma, and S. Venture Fields,
Panuke deep gas discovery

Other Fields:

Panuke deep gas discovery

Source: Cambridge Energy Research Associates.
Updated April 2005
40916-37

at unexpectedly high rates, and several bouts of reserve writedowns have occurred. Even with the development of the nearby Alma and South Venture fields, each adding 0.13 and 0.15 Bcf per day in late 2003 and late 2004, respectively, production has struggled to remain at around 0.4 to 0.45 Bcf per day. The last field to be developed, Glenelg, has been deemed uneconomic. In mid-2006 new compression will be added to boost output from around 0.4 Bcf per day to 0.45 Bcf per day. The deep Panuke discovery, containing some sulfur, which will require high-cost offshore processing, is not as yet sanctioned for development. As more reserves are sought to render Panuke economic, the discovery is assumed in this outlook to be developed by 2009, increasing production in the Sable area to 0.5 Bcf per day in 2010.

In the area around the Sable fields numerous single well discoveries were made in the 1980s. These discoveries could eventually be connected to slow the decline in the Sable complex. The Chebucto and Citnalta discoveries are the largest.

Since 2000, exploration drilling in the Sable area has not been successful, with the exception of the Annapolis G-24 Wildcat, drilled in 2002 in 5,500 feet of water. Companies are allowing leases to expire, with only a few appraisal wells expected to be drilled in 2005.

Initial associated gas production from the Hibernia area, offshore Newfoundland, is projected to commence by around 2015 from the Whiterose field. CERA expects that this gas will not be brought to market by pipeline; rather, it may be transported as compressed natural gas. The other producing oil fields, Hibernia and Terra Nova, contain significant reserves of associated gas.

To the north on the Labrador shelf, several large discoveries were made in the late 1970s and early 1980s. These discoveries are Bjarni, Gudrid, and Snorri, with combined resources of 5 Tcf. The threat of iceberg scouring of the shallow shelf bottom presents a development concern.

MACKENZIE DELTA/BEAUFORT SEA

In the Mackenzie Delta in northwest Canada, 6 Tcf of proved gas reserves, discovered in the 1970s, is assumed to be available in three main fields: Taglu, Parsons Lake, and Niglintgak. In 2001 the Tuk M-18 discovery was made, testing 30 MMcf per day with reserves of 0.5 Tcf. Since 1999, much of the area, including the offshore Beaufort Sea, has been leased with significant work commitments requiring numerous wildcats to be drilled in the next few years. This past winter several wildcats were drilled. This gas awaits a pipeline to access the market.

The companies that constitute the Mackenzie Delta Producers Group have submitted to the Canadian National Energy Board a proposal for regulatory review of the 760-mile Mackenzie Valley pipeline extending to northern Alberta. Recently, the negotiations have not been going smoothly, putting pressure on the schedule for completion of the pipeline but assuming all the approvals are reached by late 2006, a decision will then be made whether to proceed, and pipeline construction could begin in 2007 with completion by early 2010. Initial production is projected for late 2010, ramping up to 1.2 Bcf per day in 2011. The recent quickening pace of the Alaska gas pipeline project could pressure the Mackenzie pipeline, potentially resulting in delays.*

*See the CERA Alert *Mackenzie Valley Pipeline Delayed: Will History Repeat Itself?*

BRITISH COLUMBIA OFFSHORE

An attempt to open the British Columbia offshore to exploration in the Queen Charlotte Basin is under way. Although the BC government is ready to open the area, the federal government is delaying a decision while unanswered questions are addressed. The controversy involves a 33-year old Canadian government freeze on the offshore. It is possible the fate of the moratorium could be determined in 2006; if it is lifted, the establishment of a regulatory regime and local agreements could allow seismic by 2010 and drilling by 2012.

CONCLUSION

North American gas capacity from 2004 to 2012 will remain on an undulating plateau, with a steeper decline evident past 2010. The 2.6 Bcf per day decline in the United States from 2004 to 2012 is mostly offset by a 2.5 Bcf per day increase in Canada. Generally flat North American capacity contrasts with a growing appetite for gas consumption, primarily in the power sector, which translates into increasing LNG import requirements. ■

DOE Meeting on ***BALANCING NATURAL GAS SUPPLY AND DEMAND***

Natural Gas Supply Overview

December 19-20, 2005

Overview of Presentation

BACKGROUND

- NPC North American Supply Outlook
- Supply Update – Actual vs NPC

KEY ISSUES

- Gulf of Mexico
- Western Canadian Sedimentary Basin
- Non-Conventional Gas Basins
- Arctic Gas
- LNG Imports
- Access Considerations
- Technology Considerations

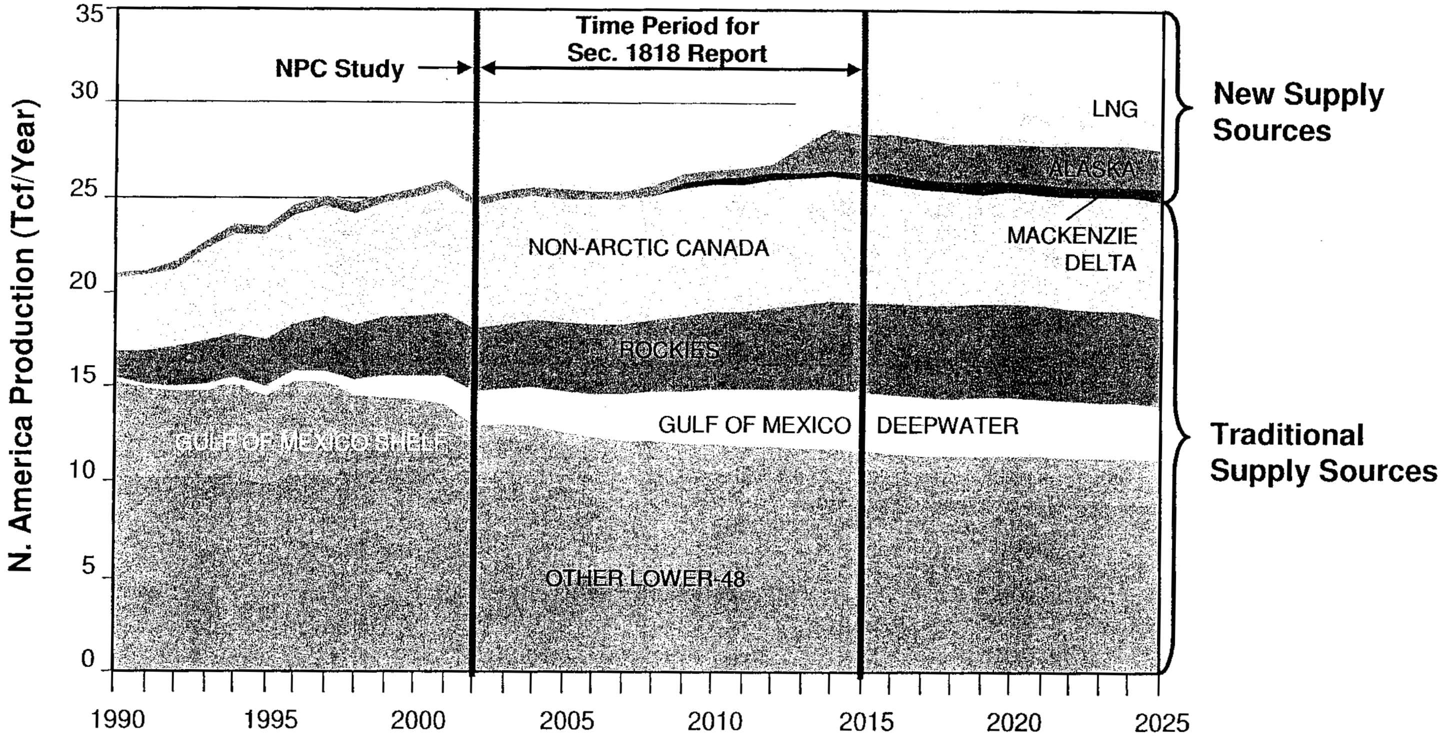
RECOMMENDATIONS & PROGRESS

- Key NPC Study Supply Recommendations

Natural Gas Supply Overview

North American Supply Outlook – NPC 2003 Study (Reactive Path)

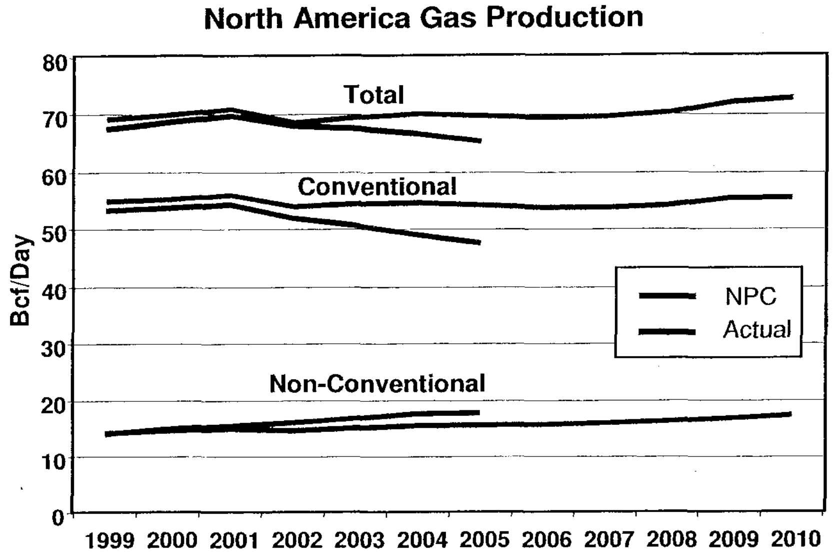
North America Natural Gas Supply Outlook

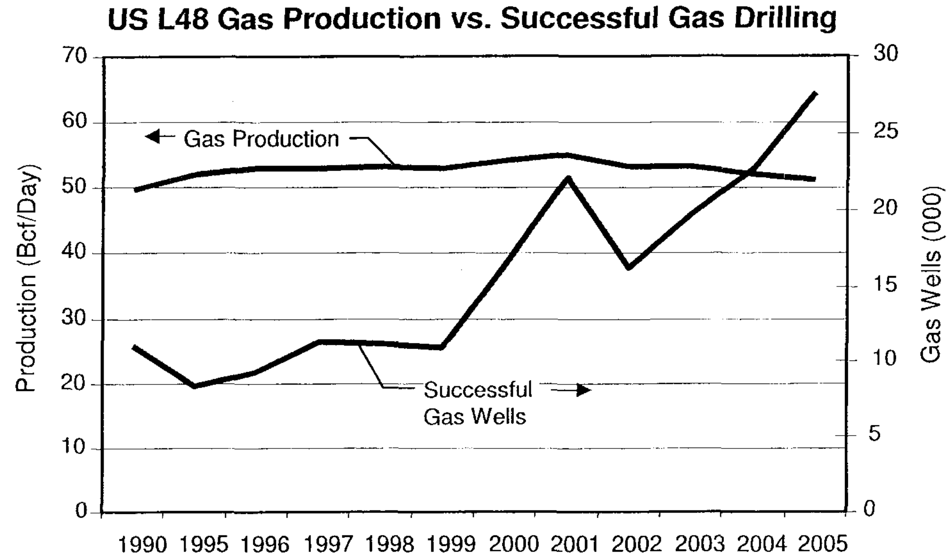


- In the 1990's, natural gas production increased steadily to meet growing demand.
- After 2000, natural gas supplies became "tight" and have continued to "tighten".
- Looking forward, traditional sources of gas supply are expected to remain essentially constant.
- LNG and Arctic natural gas will be essential for meeting future growth of demand.

Natural Gas Supply Overview

Supply Update – Actual vs NPC Projections (Reactive Path)

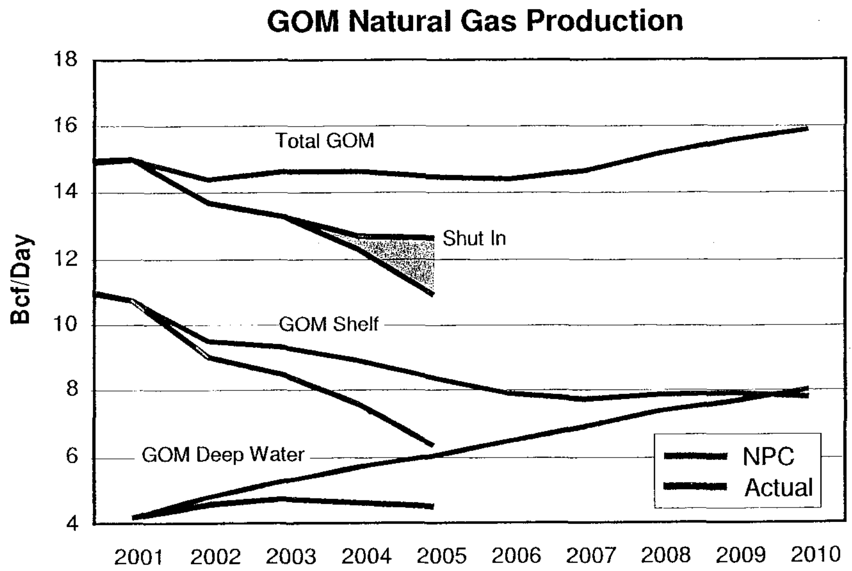


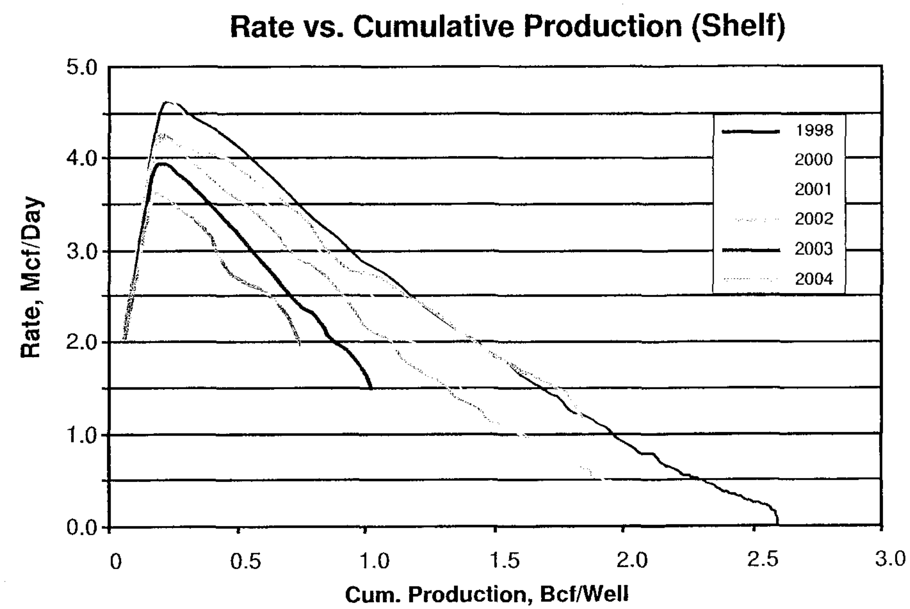


- **Conventional gas production had been declining, partially offset by non-conventional gas development.**
- **Production declines are most noticeable in offshore Gulf of Mexico (GOM) (Shelf and Deepwater) and Western Canada.**
- **Non-conventional gas production is higher due to increased drilling and new/expanded tight gas and gas shale plays.**
- **Natural gas drilling is at record levels; change in type of reserves added (higher R/P reserves) has limited production response.**

Natural Gas Supply Overview

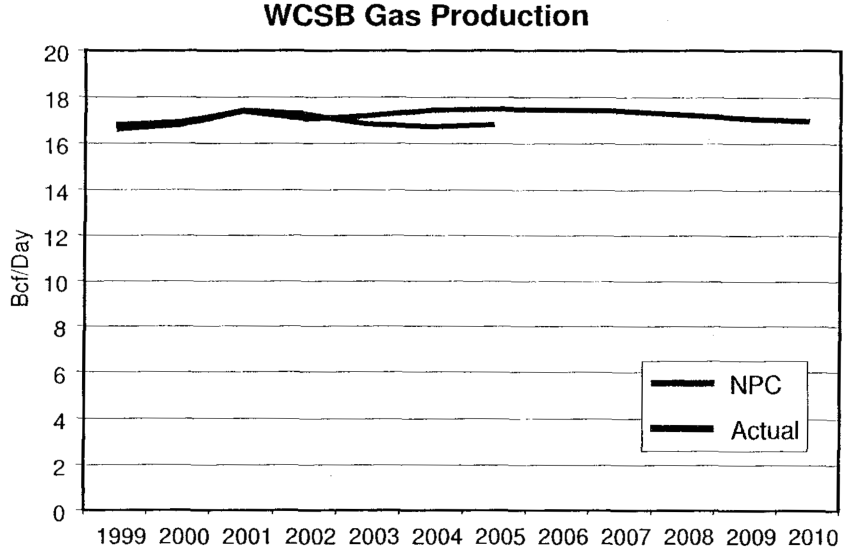
Gulf of Mexico Basin (Shelf/Deepwater)

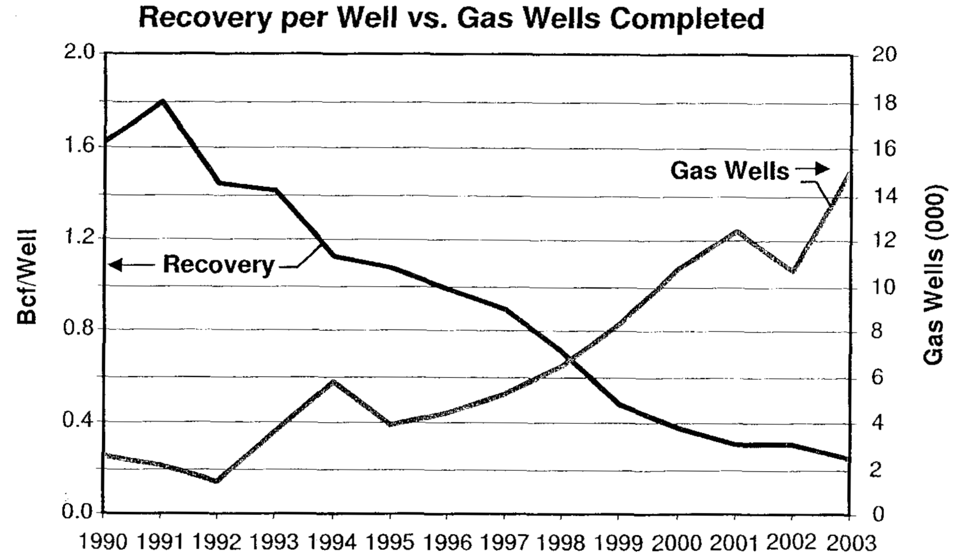




- **GOM shelf gas production has declined by nearly 2.6 Bcf/day, since 2001 (excluding effect of hurricanes); opportunities continue to become smaller; hurricanes reduced gas production by an additional 1.7 Bcf/day in 2005.**
- **Deepwater projects are delayed and less gas prone than expected.**
- **Sustaining GOM production will be challenging given recent disappointing exploration results.**

Western Canada Sedimentary Basin (WCSB)



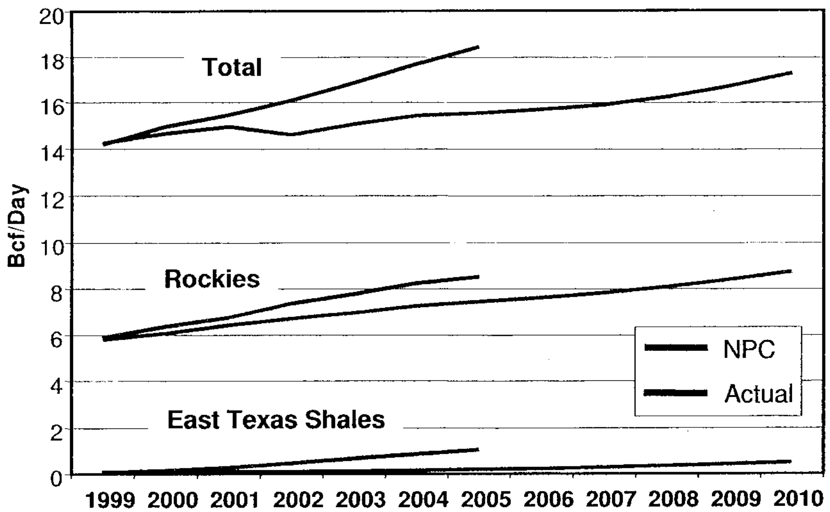


- **WCSB gas production has fallen below NPC expectations, despite record gas well drilling.**
- **Well productivity continues its long-term decline, dominated by shallow in-fill drilling.**
- **Non-conventional gas supplies are less developed than in the US; industry is beginning to develop CBM, consistent with NPC expectations.**

Natural Gas Supply Overview

Non-Conventional Basins

Non-Conventional Gas Production



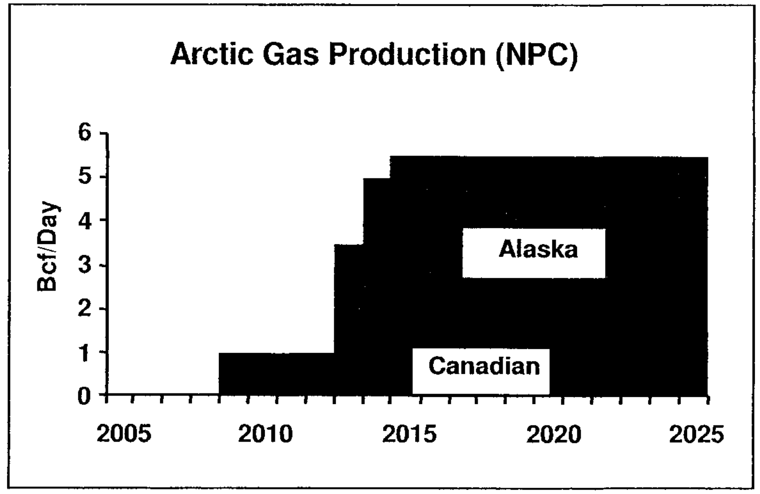
U.S. Natural Gas Well Drilling

	Total Gas Wells	Actual Unconventional Gas Wells	NPC Unconventional Gas Wells*
	(Wells/Yr)	(Wells/Yr)	(Wells/Yr)
2001	22,100	12,700	10,600
2002	16,200	11,900	9,900
2003	19,700	13,400	9,400
2004	22,700	14,100	9,200

*Includes "low perm conventional"

- **Non-conventional gas is being intensely developed with activity levels above NPC expectations.**
- **Resource base for certain gas shale and tight gas basins may be higher than in NPC assessments.**
- **CBM development is in-line with NPC expectations; permitting constraints are limiting pace of drilling.**

Natural Gas Supply Overview
Arctic Gas



Mackenzie Gas Project

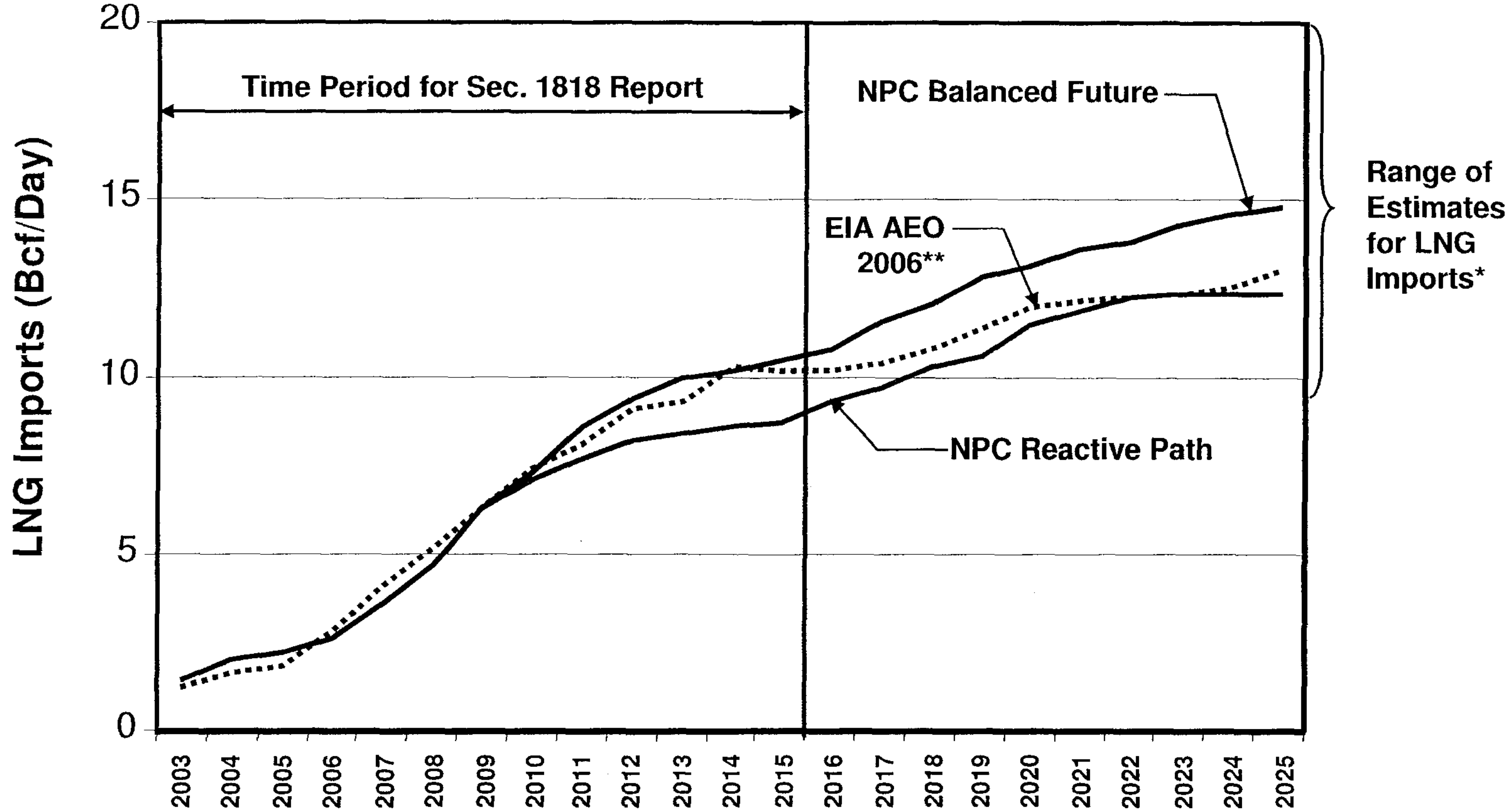
- NPC Assumptions - - 2009 start-up at 1 Bcf/d; expansion to 1.5 Bcf/d in 2015
- Outlook - - Project scope consistent; start-up timing likely delayed by 2 years

Alaska Gas Pipeline

- NPC Assumptions - - 2013 start-up at 2.5 Bcf/d; full volume of 4 Bcf/d in 2014
- Outlook - - Project scope consistent; start-up timing likely 1-2 years later

Natural Gas Supply Overview

LNG Imports



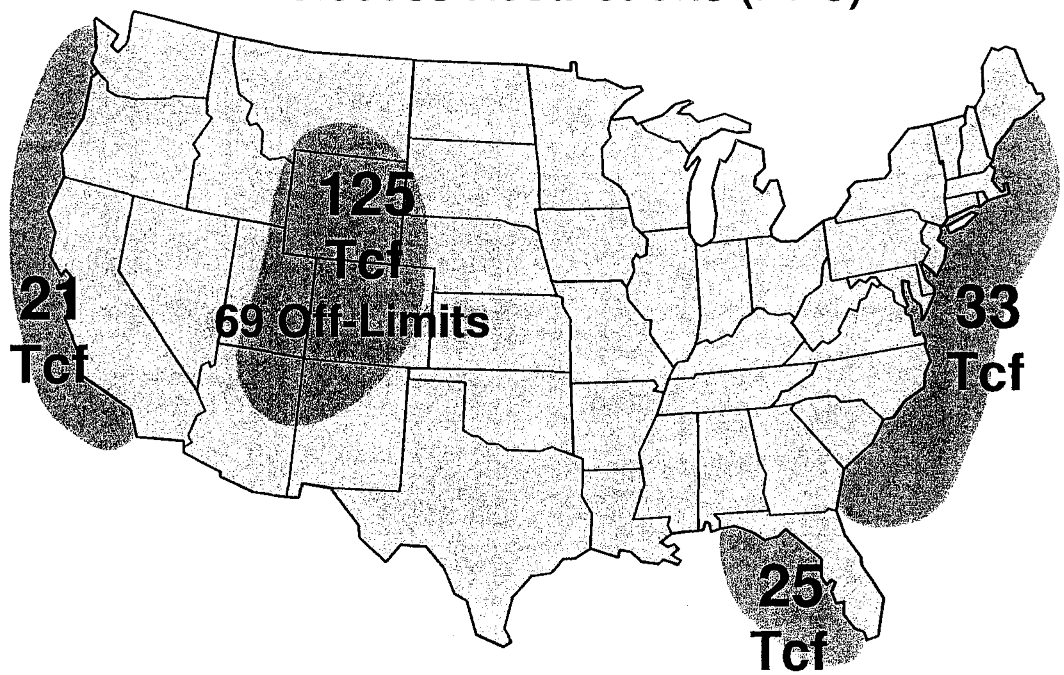
*Source: EIA AEO 2005.
**Includes LNG plants at Altamira and Baja in Mexico.

- **Recent LNG terminal expansions and developments are in line with NPC expectations.**
- **Considerable differences exist on the longer-term outlook for LNG imports.**

Natural Gas Supply Overview

Access Considerations

Natural Gas Resources Impacted by Access Restrictions (NPC)



- Studies are underway to update access restrictions and resources impacted.
- Pace of permitting has slowed development in the Rockies, particularly for Powder River CBM.

Technology Progress

Technology Progress "Levers"
(% Annual Improvement)

	NPC Study*	AEO 2006
Drilling Efficiency	1.81%	0.89%
EUR/Well (Technology Effect)		
• New Field Discoveries (Onshore)	0.87%	0%
• Unconventional Gas Wells	0.87%	0%/0.25%**
Operating Efficiency	1.00%	0.52%

*Average parameters.
**0% for mature gas plays; 0.25% for immature gas plays.

- **For two decades, progress in natural gas E&P technology countered the effects of resource maturity and depletion.**
- **For the past several years, the pace of technology progress in natural gas E&P technology appears to have slowed.**
- **The decline in technology progress is reflected in reductions in the "technology levers" used in recent EIA gas supply models, compared to those used by the NPC Study.**

Key NPC Study Supply Recommendations

Increase Supply Diversity

- **Increase Access and Reduce Permitting Impediments to Development of Lower-48 Natural Gas Resources**
  + Administration efforts to expedite lease sales and permitting (NGOs in opposition)
  - Implementation in state/field offices limited by lack of resources
  - Lack of progress on access to OCS

- **Enact Enabling Legislation for an Alaska Gas Pipeline**
  + Alaska Natural Gas Pipeline Act enacted (October, 2004)
  + State of Alaska negotiations with ANS producers are well advanced

- **Process LNG Project Permit Applications within 1 Year**
  + FERC demonstrating progress toward permitting efficiency
  + Center for LNG (CLNG) has provided LNG education and advocacy
  + EPAct gives FERC primary authority for LNG terminals

- **Evaluate the appropriateness of funding levels for natural supply R&D**
  + EPAct authorizes R&D program for ultra-deep and unconventional gas resources, plus marginal wells and methane hydrates.

Policy recommendations in NPC Study remain sound, important and timely.
Should more robust recommendations be pursued?

EXTENDED RANGE FORECAST OF ATLANTIC SEASONAL HURRICANE ACTIVITY, INDIVIDUAL MONTHLY ACTIVITY AND U.S. LANDFALL STRIKE PROBABILITY FOR 2006

We foresee an active Atlantic basin tropical cyclone season in 2006; however, we have reduced our projection for 2006 hurricane activity from our earlier forecasts. Landfall probabilities for the 2006 hurricane season are projected to be above their long-period averages for the East Coast and near their long-period averages for the Gulf Coast.

(as of 3 August 2006)

By Philip J. Klotzbach[1] and William M. Gray[2]

with special assistance from William Thorson[3]

This forecast as well as past forecasts and verifications are available via the World Wide Web at http://hurricane.atmos.colostate.edu/Forecasts

Emily Wilmsen, Colorado State University Media Representative, (970-491-6432) is available to answer various questions about this forecast

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[1] Research Associate
[2] Professor Emeritus of Atmospheric Science
[3] Research Associate

ATLANTIC BASIN SEASONAL HURRICANE FORECAST FOR 2006

Forecast Parameter and 1950-2000 Climatology (in parentheses)	Issue Date 6 Dec 2005	Issue Date 4 April 2006	Issue Date 31 May 2006	Observed Activity Through July 2006	Forecast Activity After 1 August	Total Seasonal Forecast
Named Storms (NS) (9.6)	17	17	17	2	13	15
Named Storm Days (NSD) (49.1)	85	85	85	5.5	69.5	75
Hurricanes (H) (5.9)	9	9	9	0	7	7
Hurricane Days (HD) (24.5)	45	45	45	0	35	35
Intense Hurricanes (IH) (2.3)	5	5	5	0	3	3
Intense Hurricane Days (IHD) (5.0)	13	13	13	0	8	8
Net Tropical Cyclone Activity (NTC) (100%)	195	195	195	6	134	140

POST 1-AUGUST PROBABILITIES FOR AT LEAST ONE MAJOR (CATEGORY 3-4-5) HURRICANE LANDFALL ON EACH OF THE FOLLOWING COASTAL AREAS:

1) Entire U.S. coastline - 73% (average for last century is 52%)

2) U.S. East Coast Including Peninsula Florida - 64% (average for last century is 31%)

3) Gulf Coast from the Florida Panhandle westward to Brownsville - 26% (average for last century is 30%)

4) Above-average major hurricane landfall risk in the Caribbean

Notice of Author Changes

By William Gray

The order of the authorship of these forecasts has been reversed from Gray and Klotzbach to Klotzbach and Gray. After 22 years (since 1984) of making these forecasts, it is appropriate that I step back and have Phil Klotzbach assume the primary responsibility for our project's seasonal, monthly and landfall probability forecasts. Phil has been a member of my research project for the last five years and has been second author on these forecasts for the last four years. I have greatly profited and enjoyed our close personal and working relationships.

Phil is now devoting more time to the improvement of these forecasts than I am. I am now giving more of my efforts to the global warming issue and in synthesizing my projects' many years of hurricane and typhoon studies.

Phil Klotzbach is an outstanding young scientist with a superb academic record. I have been amazed at how far he has come in his knowledge of hurricane prediction since joining my project five years ago. I foresee an outstanding future for him in the hurricane field. I expect he will make many new forecast innovations and skill improvements in the coming years. I plan to continue to be closely involved in the issuing of these forecasts for the next few years.

ABSTRACT

Information obtained through July 2006 indicates that the 2006 Atlantic hurricane season will be more active than the average 1950-2000 season; however, we have reduced our prediction from our earlier forecasts. We estimate that 2006 will have about 7 hurricanes (average is 5.9), 15 named storms (average is 9.6), 75 named storm days (average is 49.1), 35 hurricane days (average is 24.5), 3 intense (Category 3-4-5) hurricanes (average is 2.3) and 8 intense hurricane days (average is 5.0). The probability of U.S. major hurricane landfall is estimated to be about 40 percent above the long-period average. Landfall probabilities are based upon our expectation for another active season as well as analysis of our new steering current predictors for the East Coast and Gulf Coast of the United States.

We expect Atlantic basin Net Tropical Cyclone (NTC) activity in 2006 to be about 140 percent of the long-term average. This early August forecast is based on a newly devised extended range statistical forecast procedure which utilizes 57 years of past global reanalysis data. Analog predictors are also utilized. This 3 August forecast reduces our forecast from our early December 2005, early April 2006 and late May 2006 predictions due to small changes in June-July atmospheric and oceanic fields that indicate conditions are less favorable for tropical cyclone development in the tropical Atlantic. These changes include above-average tropical Atlantic sea level pressure, above-average tropical Atlantic trade wind strength and a decreasing trend in tropical Atlantic sea surface temperatures. Sea surface temperatures have also risen slightly in the eastern equatorial Pacific. We expect an active hurricane season for the Atlantic basin, but we do not foresee nearly as active a season as was experienced in 2004 and 2005. Seasonal updates of our 2006 forecast will be issued on 1 September and 3 October. A seasonal summary and forecast verification will be issued in late November.

Acknowledgment

We are grateful to the National Science Foundation (NSF) and Lexington Insurance Company (a member of the American International Group (AIG)) for providing partial support for the research necessary to make these forecasts. We also thank the GeoGraphics Laboratory at Bridgewater State College (MA) for their assistance in developing the Landfalling Hurricane Probability Webpage (available online at http://www.e-transit.org/hurricane).

The second author gratefully acknowledges valuable input to his CSU research project over many years by former graduate students and now colleagues Chris Landsea, John Knaff and Eric Blake. We also thank Professors Paul Mielke and Ken Berry of Colorado State University for much statistical analysis and advice over many years.

DEFINITIONS

Atlantic Basin – The area including the entire North Atlantic Ocean, the Caribbean Sea, and the Gulf of Mexico.

El Niño – (EN) A 12-18 month period during which anomalously warm sea surface temperatures occur in the eastern half of the equatorial Pacific. Moderate or strong El Niño events occur irregularly, about once every 3-7 years on average.

Hurricane – (H) A tropical cyclone with sustained low-level winds of 74 miles per hour (33 ms^{-1} or 64 knots) or greater.

Hurricane Day – (HD) A measure of hurricane activity, one unit of which occurs as four 6-hour periods during which a tropical cyclone is observed or estimated to have hurricane intensity winds.

Hurricane Destruction Potential – (HDP) A measure of a hurricane's potential for wind and storm surge destruction defined as the sum of the square of a hurricane's maximum wind speed (in 10^4 $knots^2$) for each 6-hour period of its existence.

Intense Hurricane - (IH) A hurricane which reaches sustained low-level winds of at least 111 mph (96 knots or 50 ms^{-1}) at some point in its lifetime. This constitutes a category 3 or higher on the Saffir/Simpson scale (also termed a "major" hurricane).

Intense Hurricane Day – (IHD) Four 6-hour periods during which a hurricane has an intensity of Saffir/Simpson category 3 or higher.

Named Storm – (NS) A hurricane or a tropical storm.

Named Storm Day – (NSD) As in HD but for four 6-hour periods during which a tropical cyclone is observed (or is estimated) to have attained tropical storm intensity winds.

NTC – Net Tropical Cyclone Activity –Average seasonal percentage mean of NS, NSD, H, HD, IH, IHD. Gives overall indication of Atlantic basin seasonal hurricane activity.

ONR – Previous year October-November SLPA of subtropical Ridge in eastern Atlantic between 20-30°W.

QBO – Quasi-Biennial Oscillation – A stratospheric (16 to 35 km altitude) oscillation of equatorial east-west winds which vary with a period of about 26 to 30 months or roughly 2 years; typically blowing for 12-16 months from the east, then reversing and blowing 12-16 months from the west, then back to easterly again.

Saffir/Simpson (S-S) Category – A measurement scale ranging from 1 to 5 of hurricane wind and ocean surge intensity. One is a weak hurricane; whereas, five is the most intense hurricane.

SLPA – Sea Level Pressure Anomaly – The deviation of sea level pressure from observed long-term average conditions.

SOI – Southern Oscillation Index – A normalized measure of the surface pressure difference between Tahiti and Darwin.

SST(s) – Sea Surface Temperature(s)

SSTA(s) – Sea Surface Temperature(s) Anomalies

Tropical Cyclone – (TC) A large-scale circular flow occurring within the tropics and subtropics which has its strongest winds at low levels; including hurricanes, tropical storms and other weaker rotating vortices.

Tropical Storm – (TS) A tropical cyclone with maximum sustained winds between 39 (18 ms^{-1} or 34 knots) and 73 (32 ms^{-1} or 63 knots) miles per hour.

ZWA – Zonal Wind Anomaly – A measure of the upper level (~200 mb) west to east wind strength. Positive anomaly values mean winds are stronger from the west or weaker from the east than normal.

1 knot = 1.15 miles per hour = 0.515 meters per second

1 Introduction

This is the 23^{rd} year in which the CSU Tropical Meteorology Project has made forecasts of the upcoming season's Atlantic basin hurricane activity. Our forecast team has shown that a sizable portion of the year-to-year variability of Atlantic tropical cyclone (TC) activity can be hindcast with skill exceeding climatology. These forecasts are based on a statistical methodology derived from 57 years of past data and a separate study of analog years which have similar precursor circulation features to the current season. Qualitative adjustments are added to accommodate additional processes which may not be explicitly represented by our statistical analyses. These evolving forecast techniques are based on a variety of climate-related global and regional predictors previously shown to be associated with the forthcoming seasonal Atlantic basin tropical cyclone activity and landfall probability. We believe that seasonal forecasts must be based on methods that show significant hindcast skill in application to long periods of prior data. It is only through hindcast skill that one can demonstrate that seasonal forecast skill is possible. This is a valid methodology provided that the atmosphere continues to behave in the future as it has in the past.

A variety of atmosphere-ocean conditions interact with each other to cause year-to-year and month-to-month hurricane variability. The interactive physical linkages between these many physical parameters and hurricane variability are complicated and cannot be well elucidated to the satisfaction of the typical forecaster making short range (1-5 days) predictions where changes in the momentum fields are the crucial factors. Seasonal and monthly forecasts, unfortunately, must deal with the much more complicated interaction of the energy-moisture fields with the momentum fields.

We find that there is a rather high (50-60 percent) degree of year-to-year hurricane forecast potential if one combines 4-5 semi-independent atmospheric-oceanic parameters together. The best predictors (out of a group of 4-5) do not necessarily have the best individual correlations with hurricane activity. The best forecast parameters are those that explain the portion of the variance of seasonal hurricane activity that is not associated with the other variables. It is possible for an important hurricane forecast parameter to show little direct relationship to a predictand by itself but to have an important influence when included with a set of 4-5 other predictors.

In a five-predictor empirical forecast model, the contribution of each predictor to the net forecast skill can only be determined by the separate elimination of each parameter from the full five predictor model while noting the hindcast skill degradation. When taken from the full set of predictors, one parameter may degrade the forecast skill by 25-30 percent, while another degrades the forecast skill by only 10-15 percent. An individual parameter that, through elimination from the forecast, degrades a forecast by as much as 25-30 percent may, in fact, by itself, show much less direct correlation with the predictand. A direct correlation of a forecast parameter may not be the best measure of the importance of this predictor to the skill of a 4-5 parameter forecast model. This is the nature of the seasonal or climate forecast problem where one is dealing with a very complicated atmospheric-oceanic system that is highly non-linear. There is a maze of changing physical linkages between the many variables. These linkages can undergo unknown changes from weekly to decadal time scales. It is impossible to understand how all these processes interact with each other. It follows that any seasonal or climate forecast scheme showing significant hindcast skill must be empirically derived. No one can completely understand the full complexity of the atmosphere-ocean system or develop a reliable scheme for forecasting the myriad non-linear interactions in the full-ocean atmosphere system.

2 Newly-Developed 1 August Forecast Scheme

We have recently developed a new 1 August statistical seasonal forecast scheme for prediction of Net Tropical Cyclone (NTC) activity. This scheme was developed on NOAA/NCEP reanalysis data from 1949-1989. It was then tested on independent data from 1990-2005 to insure that the forecast shows similar skill in this later forecast period. As a rule, predictors were only added to the scheme if they explained an additional three percent of the variance of NTC in both the dependent period (1949-1989) and the independent period (1990-2005)

The pool of four predictors for this new extended range forecast is given and defined in Table 1. The location of each of these new predictors is shown in Fig. 1. Strong statistical relationships can be extracted via combinations of these predictive parameters (which are available by the end of July), and quite skillful Atlantic basin forecasts of NTC activity for the season can be made if the atmosphere and ocean continue to behave in the future as they have during the hindcast period of 1949-2005. Sixty percent of the variance in NTC is explained over the 1949-2005 period, and on independent data (1900-1948), using the same equations and predictors, 49 percent of the variance is explained. This is comparable to what would be expected with independent data as a jackknife regression technique on the 1949-2005 period indicated 52 percent of the variance could be explained. This gives us increased confidence that the new statistical scheme should be of considerable value in the future.

Our statistical forecast for the other predictors (i.e., named storms, hurricanes) is then adjusted by the predicted statistical value of NTC. For example, if a typical season has 10 named storms and the predicted NTC value is 120%, the predicted number of named storms for the season would be 12 (10 * 120%).

August Seasonal Forecast Predictors

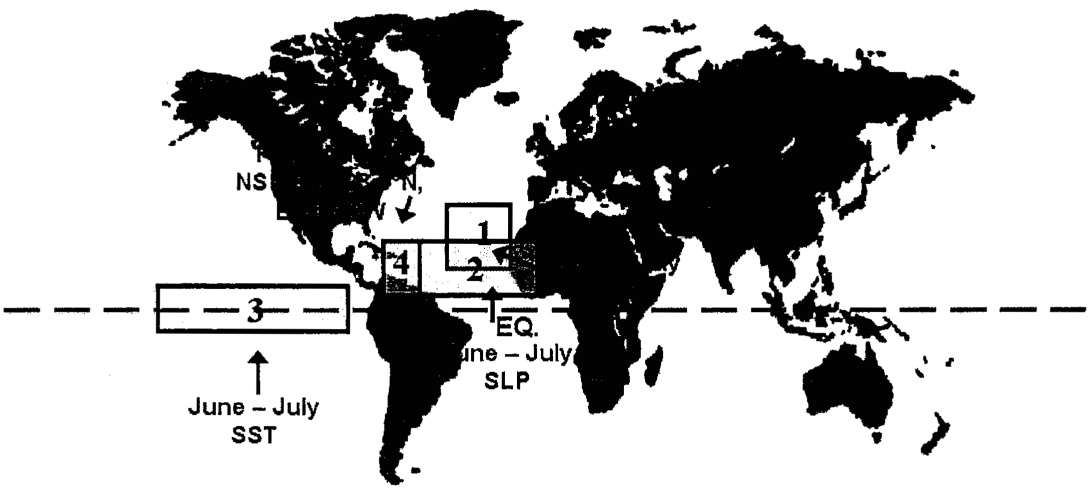

Figure 1: Location of predictors for the 1 August forecast for the 2006 hurricane season.

Table 1: Listing of 1 August 2006 predictors for this year's hurricane activity. A plus (+) means that positive values of the parameter indicate increased hurricane activity this year, and a minus (-) means that positive values of the parameter indicate decreased hurricane activity this year. The combination of these four predictors calls for about an average hurricane season.

Predictor	Values for 2006 Forecast
1) June-July SST (20-40°N, 15-35°W) (+)	+0.8 SD
2) June-July SLP (10-25°N, 10-60°W) (-)	+0.3 SD
3) June-July NINO3 Index (5°S-5°N, 90-150°W) (-)	+0.3 SD
4) Pre-1 August Named Storm Days – South of 23.5°N, East of 75°W	0

Table 2 shows our statistical forecast for the 2006 hurricane season and the comparison of this forecast with climatology (average season between 1950-2000). Our statistical forecast is calling for about average activity this year, which adds additional support for the reduction of our forecast from our previous early-season predictions.

Table 2: 1 August statistical forecast for 2006.

Predictands and Climatology	Statistical Forecast Numbers
Named Storms (NS) – 9.6	10.0
Named Storm Days (NSD) – 49.1	51.1
Hurricanes (H) – 5.9	6.1
Hurricane Days (HD) – 24.5	25.5
Intense Hurricanes (IH) – 2.3	2.4
Intense Hurricane Days (IHD) – 5.0	5.2
Net Tropical Cyclone Activity (NTC) – 100	104

2.1 Physical Associations among Predictors Listed in Table 1

Brief descriptions of our 1 August predictors follow:

Predictor 1. June-July SST in the Northeastern Subtropical Atlantic (+)

(20°-40°N, 15-35°W)

Warm sea surface temperatures in this area in June-July correlate very strongly with anomalously warm sea surface temperatures in the tropical Atlantic throughout the upcoming hurricane season. Anomalously warm sea surface temperatures are important for development and intensification of tropical cyclones by infusing more latent heat into the system (Goldenberg and Shapiro 1998). In addition, associated with anomalously warm June-July SSTS are weaker trade winds. Weaker trade winds cause less evaporation and upwelling of the sea surface which therefore feeds back into keeping the tropical Atlantic warm. In addition, weaker trade winds imply that there is less vertical wind shear across the tropical Atlantic. Weak wind shear is favorable for tropical cyclone development and intensification (Gray 1968, Gray 1984a, Goldenberg and Shapiro 1996, Knaff et al. 2004). Lastly, there is a strong positive correlation (~0.5) between anomalously warm June-July SSTs in the subtropical northeastern Atlantic and low sea level pressures in the tropical Atlantic and Caribbean during the heart of the hurricane season. Low sea level pressures imply decreased subsidence and enhanced mid-level moisture. Both of these conditions are favorable for tropical cyclogenesis and intensification (Knaff 1997).

Predictor 2. June-July SLP in the Tropical Atlantic (-)

(10-25°N, 10-60°W)

Low sea level pressure in the tropical Atlantic in June-July implies that early summer conditions in the tropical Atlantic are favorable for an active tropical cyclone season with increased vertical motion, decreased stability and enhanced mid-level moisture. There is a strong auto-correlation ($r > 0.5$) between June-July sea level pressure anomalies and August-October sea level pressure anomalies in the tropical Atlantic. Low sea level pressure in the tropical Atlantic also correlates quite strongly ($r > 0.5$) with reduced trade winds (weaker easterlies) and anomalously easterly upper-level winds (weaker westerlies). The combination of these two features implies weaker vertical wind shear and therefore more favorable conditions for tropical cyclone development in the Atlantic (Gray 1968, Gray 1984a, Goldenberg and Shapiro 1996).

Predictor 3. June-July Nino3 Index (-)

(5°S-5°N, 90-150°W)

Cool sea surface temperatures in the Nino3 region during June-July imply that a La Niña event is currently present. In general, positive or negative anomalies in the Nino3 region during the early summer persist throughout the remainder of the summer and fall. El Niño conditions shift the center of the Walker Circulation eastward which causes increased convection over the central and eastern tropical Pacific. This increased convection in the central and eastern Pacific manifests itself in anomalous upper-level westerlies across the Caribbean and tropical Atlantic, thereby increasing vertical wind shear and reducing Atlantic basin hurricane activity. The relationship between ENSO and Atlantic hurricane activity has been well-documented in the literature (e.g., Gray 1984a, Goldenberg and Shapiro 1996, Elsner 2003, Bell and Chelliah 2006).

Predictor 4. Named Storm Days South of 23.5°N, East of 75°W (+)

Most years do not have named storm formations in June and July in the tropical Atlantic; however, if deep tropical formations do occur, it indicates that a very active hurricane season is likely. For example, the six years with the most named storm days in the deep tropics in June and July (since 1949) are 1966, 1969, 1995, 1996, 1998 and 2005. All six of these seasons were very active. When storms form in the deep tropics in the early part of the hurricane season, it indicates that conditions are already very favorable for TC development. In general, the start of the hurricane season is restricted by thermodynamics (warm SSTs, unstable lapse rates), and therefore deep tropical activity early in the hurricane season implies that the thermodynamics are already quite favorable for TC development. Also, this predictor's correlation with seasonal NTC is 0.53 over the 1949-2005 period, and when tested on independent data (1900-1948), the correlation actually improves to 0.63, which gives us increased confidence in its use as a seasonal predictor.

2.2 Hindcast Skill

Table 3 shows the degree of hindcast variance (r^2) explained by our new 1 June forecast scheme based on our 41-year developmental dataset (1949-1989), our skill on the independent dataset (1990-2005), and our skill over the entire dataset (1949-2005).

Note that the scheme generally shows improved skill in the independent dataset, which lends increased confidence in its use.

Table 3: Variance (r^2) explained for our new 1 August forecast scheme for NTC in the developmental dataset (1949-1989), in the independent dataset (1990-2005), and over the entire dataset (1949-2005).

Variable	Variance (r^2) Explained Developmental Dataset (1949-1989)	Variance (r^2) Explained Independent Dataset (1990-2005)	Variance (r^2) Explained Entire Dataset (1949-2005)
NTC	0.52	0.76	0.60

3 Predictions of Individual Monthly Atlantic TC Activity for August, September and October

A new aspect of our climate research is the development of TC activity predictions for individual months. There are often monthly periods within active and inactive Atlantic basin hurricane seasons which do not conform to the overall season. For example, 1961 was an active hurricane season (NTC of 222), but there was no TC activity during August; 1995 had 19 named storms, but only one named storm developed during a 30-day period during the peak of the hurricane season between 29 August and 27 September. By contrast, the inactive season of 1941 had only six named storms (average 9.3), but four of them developed during September. During the inactive 1968 hurricane season, three of the eight named storms formed in June (June average is 0.5).

We have conducted new research to see how well various sub-season or individual monthly trends of TC activity can be forecast. This effort has recently been documented in papers by Blake and Gray (2004) for August and Klotzbach and Gray (2003) for September. These reports show that it is possible to develop skillful prediction schemes for August-only and September-only Atlantic basin tropical cyclone activity. We have also developed a separate October forecast scheme. On average, August, September, and October have about 26%, 48%, and 17% or 91% of the Atlantic basin's NTC activity. Initial August-only forecasts have now been made by Blake for the last six years (2000-2005), and the verification of these forecasts looks promising. The verification of the September-only and October-only forecasts also appears to show skill.

3.1 Independent August-Only Statistical Forecast

Figure 2 and Table 4 list the predictors used in the August-only hindcast (Blake and Gray 2004) for each of the seven different forecast parameters. The table also shows hindcast skill for the 51-year period 1950-2000, as well as the independent jackknife hindcast skill over this period. Table 5 gives the predictor values for August 2006. Table 6 gives our independent statistical prediction for August 2006. These predictors indicate well above-average activity for August 2006. The most skillful August predictors, in general, call for a very active month, so we are calling for considerable activity during the month.

Predictor Map

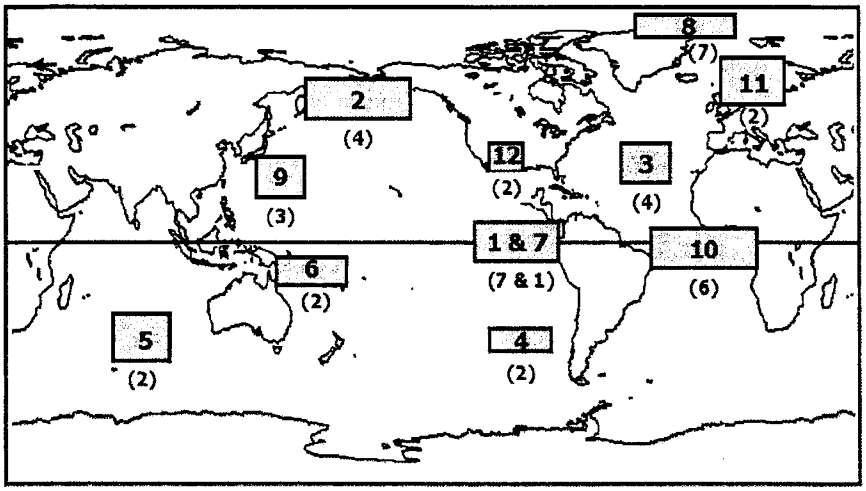

Figure 2: Global map showing locations of August-only TC predictors. Table 4 provides a listing and description of these predictors. The numbers in the boxes are keyed to the descriptions given in Table 4. The numbers in parentheses beneath each box indicate how many individual parameters (NS, NSD, etc.) are obtained from each predictor.

Table 4: Listing of predictors chosen for each forecast parameter and the total hindcast variance explained by these predictors for the August-only forecast. The name and atmospheric parameter utilized in each predictor is given below – where the number is keyed to Fig. 2.

Forecast Parameter	Number of Predictors	Predictors Chosen From Table	Variability Explained by Hindcast (r^2) (1949-1999)	Estimated Independent Forecast Skill (Jackknife)
NS	5	3, 6, 7, 9, 11	0.55	0.41
NSD	5	1, 2, 3, 8, 10	0.71	0.61
H	4	1, 2, 8, 10	0.57	0.47
HD	5	3, 4, 8, 9, 10	0.69	0.59
IH	5	1, 3, 5, 8, 12	0.68	0.59
IHD	5	1, 4, 5, 6, 9	0.78	0.72
NTC	5	1, 2, 8, 10, 12	0.74	0.66

Table 5: August 2006 predictors. The sign of the predictor associated with increased tropical cyclone activity is in parentheses.

Predictors	2006 Observed Values	Effect on 2006 Hurricane Season
Galapagos July 200 mb V (-)	-1.0 SD	**Enhance**
Bering Sea July SLP (-)	-1.0 SD	**Enhance**
Atlantic Ocean July SLP (-)	+0.8 SD	Suppress
SE Pacific July 200 mb U (-)	+0.2 SD	Suppress
S. Indian Ocean July 500 mb Geo Ht. (-)	+1.0 SD	Suppress
Coral Sea July 200 mb U (+)	+0.7 SD	**Enhance**
Galapagos July 200 MB U (-)	-0.5 SD	**Enhance**
North Greenland June 200 MB U (+)	+0.5 SD	**Enhance**
Northwest Pacific June SLP (+)	+1.0 SD	**Enhance**
S. Atlantic Ocean April SLP (-)	-0.6 SD	**Enhance**
Scandinavia February SLP (-)	+0.4 SD	Suppress
SW USA January SLP (-)	-1.0 SD	**Enhance**

Table 6: Independent August-only prediction of 2006 hurricane activity based on Blake and Gray (2004). August climatology is shown in parentheses.

Parameter	Statistical Model	Qualitative Adjustment
NS	3.3 (2.8)	4
NSD	21.1 (11.8)	22
H	2.9 (1.6)	3
HD	8.1 (5.7)	11
IH	0.7 (0.6)	1
IHD	2.0 (1.2)	3
NTC	53.6 (26.1)	50

3.2 Independent September-Only Statistical Forecast

Figure 3 and Table 7 list the predictors used in the September-only hindcast (Klotzbach and Gray 2003) for each of the seven different forecast parameters. The table also shows hindcast skill for the 51-year period 1950-2000, as well as the independent jackknife hindcast skill over this period. Table 8 gives the predictor values for September 2006. Table 9 gives our independent statistical prediction for September 2006. Predictor values for September 2006 are mixed, so our final forecast is calling for slightly above-average activity for the month.

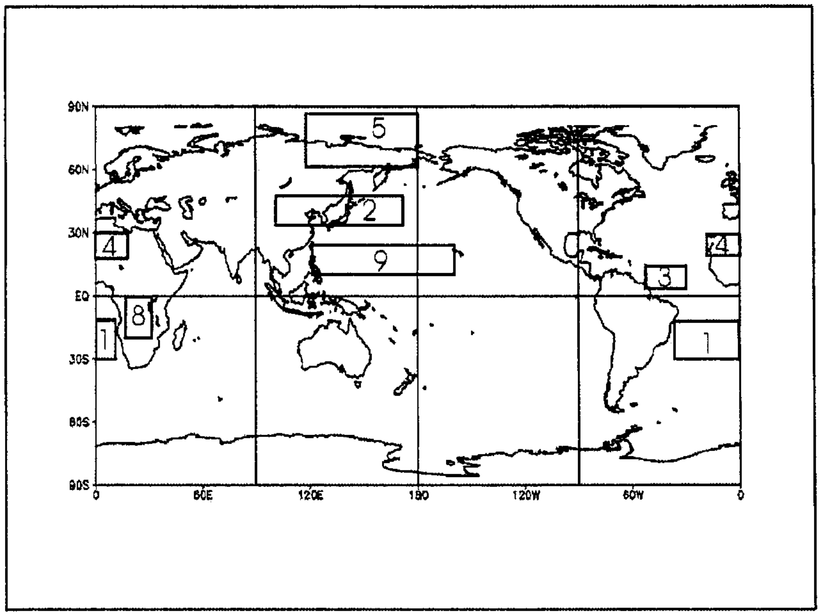

Figure 3: Predictors selected for the end of July forecast of September tropical cyclone activity. The numbers in each area are keyed to the description given in Table 7.

Table 7: Listing of predictors chosen for each forecast parameter and the total hindcast variance explained by these predictors for the September-only forecast. The name and atmospheric parameter utilized in each predictor is given below – where the number is keyed to Fig. 3.

Forecast Parameter	Number of Predictors	Predictors Chosen From Table	Variability Explained by Hindcast (r^2) (1950-2000)	Estimated Independent Forecast Skill (Jackknife)
NS	3	2, 3, 5	0.29	0.19
NSD	5	2, 3, 4, 5, 8	0.54	0.44
H	3	2, 3, 8	0.38	0.28
HD	5	2, 3, 4, 5, 8	0.60	0.51
IH	5	1, 2, 3, 5, 9	0.63	0.53
IHD	4	3, 4, 5, 9	0.63	0.54
NTC	5	2, 3, 4, 5, 9	0.75	0.68

Table 8: September 2006 predictors. The sign of the predictor associated with increased tropical cyclone activity is in parentheses.

Predictors	2006 Observed Values	Effect on 2006 Hurricane Season
South Atlantic April 1000 mb U (-)	-0.6 SD	**Enhance**
Northeast Asia July 200 mb Geo Ht. (+)	+1.3 SD	**Enhance**
Tropical Atlantic July 1000 MB U (+)	-0.8 SD	Suppress
West Africa February 1000 mb U (-)	+0.8 SD	Suppress
Northeast Siberia April 200 mb U (-)	-1.2 SD	**Enhance**
Central Africa May 200 mb V (+)	-1.4 SD	Suppress
West Pacific Jan-Feb 200 mb U (-)	+0.4 SD	Suppress

Table 9: Independent September-only prediction of 2006 hurricane activity based on Klotzbach and Gray (2003). September climatology is shown in parentheses.

Parameter	Statistical Model	Qualitative Adjustment
NS	4.1 (3.4)	5
NSD	20.8 (21.7)	25
H	2.2 (2.4)	3
HD	7.2 (12.3)	12
IH	1.8 (1.3)	2
IHD	1.5 (3.0)	4
NTC	48.3 (48.0)	60

3.3 Independent October-Only Statistical Forecast

Through examination of the NCEP/NCAR reanalysis, we have discovered four predictors that in combination explain about 50 percent of the October cross-validated variance in Net Tropical Cyclone activity for the hindcast period of 1950-2001. We are currently unable to find combinations of predictors that explain large amounts of variance for the individual tropical cyclone parameters (i.e., named storms, hurricane days, etc.). Therefore, our October forecast consists of predicting NTC and consequently increasing or decreasing October's values for the other parameters accordingly. For example, if October NTC was 150 percent of normal and a typical October had two named storms, we would forecast three named storms for October. The predictors utilized in our initial October prediction are displayed graphically in Figure 4. Table 10 gives the predictor values for October 2006. Table 11 gives our independent statistical prediction for October 2006. In general, predictors for October 2006 indicate slightly below-average activity for the month, and our final forecast for October 2006 is in line with our statistical prediction.

OCTOBER PREDICTORS

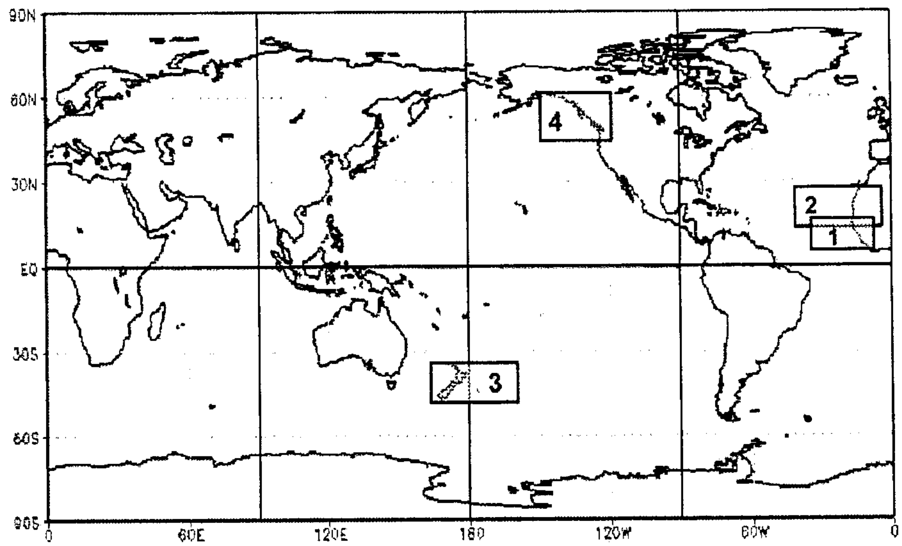

Figure 4: Location of 1 August predictors for October tropical cyclone activity.

Table 10: October 2006 predictors. The sign of the predictor associated with increased tropical cyclone activity is in parentheses.

Predictors	2006 Observed Values	Effect on 2006 Hurricane Season
Tropical Atlantic June-July SLP (-)	+0.5 SD	Suppress
Sub-Tropical Atlantic July 200 MB Ht. (+)	+1.1 SD	**Enhance**
South Pacific July 200 MB U (+)	-0.9 SD	Suppress
NW North America Previous Nov SLP (-)	0.0 SD	Neutral

Table 11: Independent October-only prediction of 2006 hurricane activity. October climatology is shown in parentheses.

Parameter	Statistical Model	Qualitative Adjustment
NS	1.4 (1.7)	2
NSD	7.3 (9.0)	11
H	0.9 (1.1)	1
HD	3.6 (4.4)	4
IH	0.2 (0.3)	0
IHD	0.6 (0.8)	0
NTC	14.6 (18.0)	15

3.4 Monthly Prediction Summary

Table 12 summarizes our individual monthly predictions and our monthly adjustments to these predictions. Based on jackknifed hindcast data from 1950-2000, the sum of the August, September, and October forecasts explains 79% of the variance in seasonal TC activity.

Table 12: August, September and October 2006 individual statistical model predictions and qualitative adjustments. The monthly climatology is given in parentheses.

Forecast Parameter	August Model Prediction	August Adjustment	September Model Prediction	September Adjustment	October Model Prediction	October Adjustment	3- Month Model Sum	3 – Month Adjusted Sum
NS	3.3 (2.8)	4	4.1 (3.4)	5	1.4 (1.7)	2	8.8	11
NSD	21.1 (11.8)	22	20.8 (21.7)	25	7.3 (9.0)	11	49.2	58
H	2.9 (1.6)	3	2.2 (2.4)	3	0.9 (1.1)	1	6.0	7
HD	8.1 (5.7)	11	7.2 (12.3)	12	3.6 (4.4)	4	18.9	27
IH	0.7 (0.6)	1	1.8 (1.3)	2	0.2 (0.3)	0	2.7	3
IHD	2.0 (1.2)	3	1.5 (3.0)	5	0.6 (0.8)	0	4.1	8
NTC	53.6 (26.1)	50	48.3 (48.0)	60	14.6 (18.0)	15	116.5	125

4 Analog-Based Predictors for 2006 Hurricane Activity

Certain years in the historical record have global oceanic and atmospheric trends which are substantially similar to 2006. These years also provide useful clues as to trends in activity that the upcoming 2006 hurricane season may bring. For this early August forecast, we project atmospheric and oceanic conditions for August through October 2006 and determine which of the prior years in our database have distinct trends in key environmental conditions which are similar to current June-July 2006 conditions. Table 13 lists our analog selections.

We select prior hurricane seasons since 1949 which have similar atmospheric-oceanic conditions to those currently being experienced. Analog years for 2006 were selected primarily on how similar they are to conditions that are currently observed such as slightly above-average tropical and North Atlantic sea surface temperatures and neutral to slightly warm ENSO conditions.

There were five hurricane seasons since 1949 with characteristics similar to what we observed in June-July and what we project for August-October. The best analog years that we could find for the 2006 hurricane season are 1953, 1958, 1980, 2001 and 2003. We anticipate that 2006 will have comparable seasonal hurricane activity to what was experienced in the average of these five years. We believe that the 2006 Atlantic basin hurricane season will be somewhat above average.

Table 13: Best analog years for 2006 with the associated hurricane activity listed for each year.

Year	NS	NSD	H	HD	IH	IHD	NTC
1953	14	64.50	6	18.00	4	6.75	127
1958	10	55.50	7	30.25	5	9.50	144
1980	11	60.00	9	38.25	2	7.25	130
2001	15	64.25	9	25.50	4	4.25	134
2003	16	79.25	7	32.75	3	16.75	174
Mean	13.2	64.7	7.6	29.0	3.6	8.9	141
2006 Forecast	**15**	**75**	**7**	**35**	**3**	**8**	**140**

5 Comparison of Forecast Techniques

Table 14 provides a comparison of our statistical and analog forecast techniques along with the final adjusted forecast and climatology. Column 1 gives activity prior to 1 August. Column 2 gives the 3-month sum of our monthly forecasts. Column 3 is our adjusted final after 1 August forecast, Column 4 is our analog scheme, column 5 is the total season adjusted forecast and column 6 is the 1950-2000 climatology.

Table 14: Comparison of our post-1 August 2006 statistical and analog forecast techniques along with our final adjusted forecast and the 1950-2000 climatology.

Forecast Parameter	(1) Pre-1 Aug Activity	(2) Sum of 3 Individual Adjusted Monthly Forecasts	(3) After-1 Aug Adjusted Final Forecast	(4) Total Season Analog Forecast	(5) Total Season Adjusted Forecast	(6) 1950-2000 Climatology
NS	2	11	13	13.2	15	9.6
NSD	5.5	58	69.5	64.7	75	49.1
H	0	7	7	7.6	7	5.9
HD	0	27	35	29.0	35	24.5
IH	0	3	3	3.6	3	2.3
IHD	0	8	8	8.9	8	5.0
NTC	6	125	134	141	140	100

6 Discussion

6.1 Reasons for Reduction of the 2006 Hurricane Seasonal Forecast

We have reduced our forecast from our earlier predictions issued in early December, early April and late May. There have been no large changes in any particular atmospheric and oceanic predictor that have caused us to do this. There has, however, been a combination of changes in the ocean/atmosphere system that indicate to us that this season is no longer likely to be as active as our earlier predictions indicated.

Physical features which have become less favorable for an active hurricane season are as follows:

1) An increase in sea level pressure values in the tropical Atlantic. Higher sea level pressure values indicate increased stability in the tropical Atlantic which inhibits tropical cyclogenesis.

2) An increase in strength of the trade winds in the tropical Atlantic. Stronger trade winds drive increased evaporation and upwelling which cools Atlantic sea surface temperatures. In addition, stronger trades usually indicate increased vertical wind shear in the tropical Atlantic.

3) A decrease in tropical Atlantic sea surface temperatures. Cooler Atlantic SSTAs (sea surface temperature anomalies) provide less latent heat (i.e., less fuel) for developing tropical cyclones.

4) An increase in Pacific eastern equatorial SSTAs. Sea surface temperatures have still not reached El Niño levels; however, increased warming implies a shift in tropical convection towards the dateline. This eastward-shifted convection often increases vertical wind shear over the tropical Atlantic.

The fact that we have had only two tropical storms during June-July does not necessarily impact our forecast for the upcoming season. There have been many active hurricane seasons (e.g., 1950, 2004, etc.) that had no activity in June and July. Last year (2005) was an unusually active early season with seven named storms and two major hurricanes before August 1. Last year broke most existing single season hurricane records.

6.2 Brief Comments on the 2005 Hurricane Season

The year of 2005 was a very unusual year, not only for Atlantic hurricanes but also for other global circulation features. We consider 2005 to be within the range of natural variation. For example, 1933 had 21 named storms and would likely have had 4-5 more storms if satellite data had been available. Also, the tremendous economic damage from last year's storms would have been only about 30-50% as much if the levees in New Orleans had not been breached.

7 Post 1-August Landfall Probabilities for 2006

7.1 Introduction

A significant focus of our recent research involves efforts to develop forecasts of the probability of hurricane landfall along the U.S. coastline. Whereas individual hurricane landfall events cannot be accurately forecast months in advance, the total seasonal probability of landfall can be forecast with statistical skill. With the observation that, statistically, landfall is a function of varying climate conditions, a probability specification has been developed through statistical analyses of all U.S. hurricane and named storm landfall events during the 20th century (1900-1999). Specific landfall probabilities can be given for all tropical cyclone intensity classes for a set of distinct U.S. coastal regions.

As shown in Table 15, NTC is a combined measure of the year-to-year mean of six indices of hurricane activity, each expressed as a percentage difference from the long-term average. Long-term statistics show that, on average, the more active the overall Atlantic basin hurricane season is, the greater the probability of U.S. hurricane landfall. For example, landfall observations during the 20th century show that a greater number of intense hurricanes strike the United States coastline in years of above-average NTC.

Table 15: NTC activity in any year consists of the seasonal total of the following six parameters expressed in terms of their long-term averages. A season with 10 NS, 50 NSD, 6 H, 25 HD, 3 IH, and 5 IHD would then be the sum of the following ratios: 10/9.6 = 104, 50/49.1 = 102, 6/5.9 = 102, 25/24.5 = 102, 3/2.3 = 130, 5/5.0 = 100, divided by six, yielding an NTC of 107.

	1950-2000 Average	
1)	Named Storms (NS)	9.6
2)	Named Storm Days (NSD)	49.1
3)	Hurricanes (H)	5.9
4)	Hurricane Days (HD)	24.5
5)	Intense Hurricanes (IH)	2.3
6)	Intense Hurricane Days (IHD)	5.0

7.2 Steering Current Prediction

We have considerably improved the statistical skill of our landfall probability forecasts through the inclusion of three April-May predictors of mid-latitude steering flow for the Florida Peninsula and the East Coast and two predictors of mid-latitude steering flow for the Gulf Coast. Based on data from the NCEP/NCAR reanalysis, using a combination of our NTC forecast and the predictors listed in Tables 16 and 17 and displayed in Figures 5 and 6, we are able to hindcast approximately 30 percent of the variance in hurricane landfall for the Gulf Coast and approximately 50 percent of the variance in hurricane landfall for the Florida Peninsula and the East Coast over the period 1950-2004. As evidenced by hurricane landfall activity in 2004 and 2005 compared with the earlier period of 1995-2003, the strength of midlatitude westerly winds related to the position of the Bermuda High, is vitally important in determining how likely storms are to make landfall along either the East Coast or the Gulf Coast. The predictors listed in Tables 16 and 17 give us some degree of skill in predicting the mid-level steering flow during the hurricane season, and therefore add skill to our landfall probabilities beyond that specified by the combination of NTC and SSTA*. New research is finding that SSTA* does not add much additional skill beyond NTC and the steering current predictors, and therefore we have now discontinued the inclusion of SSTA* in our landfall probability calculations. We are currently unable to find any June-July mid-level steering flow indicators that improve upon our 1 June hindcast skill for landfall probability.

Table 16: Listing of steering current predictors for the East Coast and Florida Peninsula. The sign of the predictor associated with increased landfall is in parentheses.

Predictor	Values for 2006 Forecast
1) April-May 500 MB Ht. (35-50°N, 60-80°W) (+)	+0.1 SD
2) April-May SLP (20-40°S, 70-110°W) (+)	+0.2 SD
3) April-May 500 MB Ht. (70-85°N, 20°W-100°E) (+)	+1.9 SD

Table 17: Listing of steering current predictors for the Gulf Coast. The sign of the predictor associated with increased landfall is in parentheses.

Predictor	Values for 2006 Forecast
1) May 500 MB Ht. (10-25°S, 20-60°W) (+)	-0.8 SD
2) April-May 500 MB Ht. (40-55°S, 120°E-170°W) (+)	+0.1 SD

East Coast Landfall Predictors

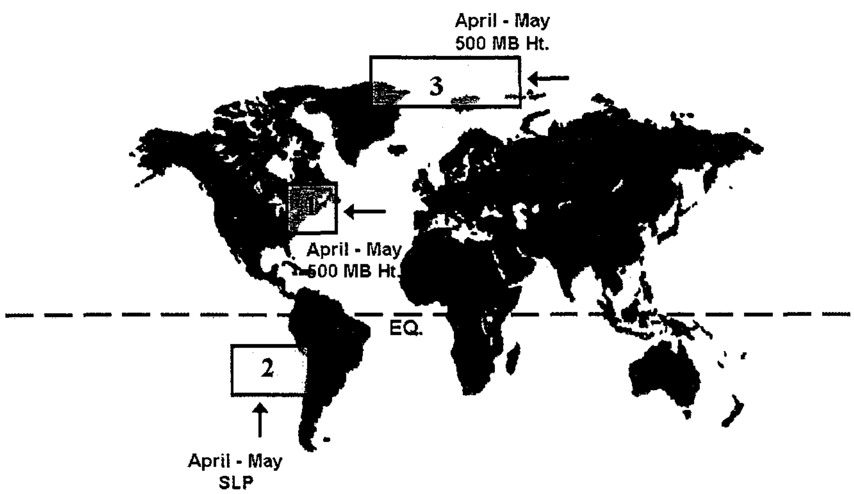

Figure 5: Listing of steering current predictors for the East Coast and Florida Peninsula.

Gulf Coast Landfall Predictors

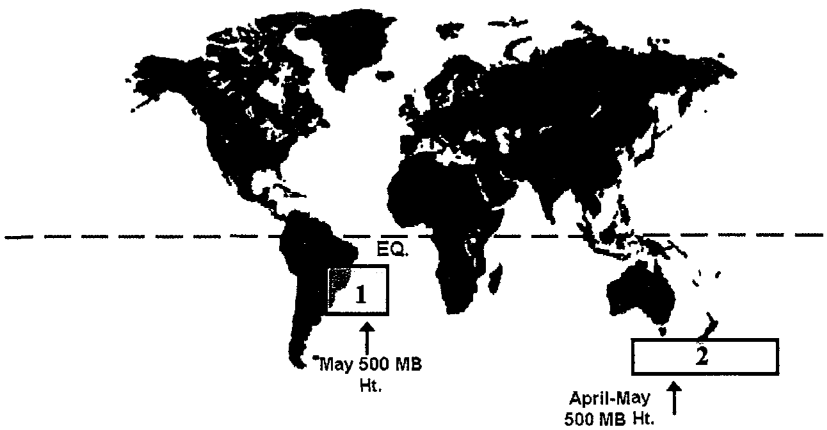

Figure 6: Listing of steering current predictors for the Gulf Coast.

7.3 Steering Current Predictor Physical Relationships

Brief descriptions of how we believe our steering current predictors relate to the steering currents likely to be present during the hurricane season are as follows:

East Coast Predictors:

Predictor 1. April-May 500 MB Geopotential Height in the Northeast United States and Canada (+)

(35-50°N, 60-80°W)

Anomalously high heights in the northeast United States during April-May, i.e., anomalous mid-level ridging, are associated with increased likelihood of hurricane landfalls along the East Coast and Florida Peninsula during the upcoming hurricane season. High heights in April-May tend to persist through August-October with an auto-correlation between the two periods of approximately 0.40. Easterly mid-level zonal wind anomalies associated with this anomalous ridging tend to drive tropical cyclones further west across the East Coast of the United States and inhibit early recurvature into the westerlies.

Predictor 2. April-May 500 MB Geopotential Height off the West Coast of South America (+)

(20-40°S, 70-110°W)

Anomalous ridging off the west coast of South America during April-May is commonly associated with strong equatorial east winds over the eastern Pacific and cold water upwelling. Such cold water upwelling is associated with a positive Southern Oscillation Index (SOI) and hence a La Niña event. La Niña events tend to persist from late May through the summer/fall period. In general, United States hurricane landfalls, especially in the Southeast, are more likely when the SOI is positive (Elsner 2003).

Predictor 3. April-May 500 MB Geopotential Height in the Arctic (+)

(70-85°N, 20°W-100°E)

Anomalously high heights in the Arctic are associated with a negative phase of the Arctic Oscillation (AO) (Thompson and Wallace 2000). A negative phase of the AO is associated with weaker westerlies across the North Atlantic. Stronger westerlies tend to steer storms away from the United States; whereas, weaker westerlies favor landfall along the East Coast of the United States (Xie et al. 2005).

Gulf Coast Predictors:

Predictor 1. May 500 MB Geopotential Height off the East Coast of South America (+)

(10-25°S, 20-60°W)

Anomalously high heights off the east coast of South America in May are strongly correlated with anomalous mid- and upper-level warming throughout the entire tropics during the spring. By the summer/fall period, a strong ridge develops over the southeastern United States with positive values of this predictor in May. This ridging tends to advect storms further west into the Gulf of Mexico and prevent early recurvature into the North Atlantic.

Predictor 2. April-May 500 MB Geopotential Height off the South Coast of New Zealand (+)

(40-55°S, 120°E-170°W)

Anomalous ridging off the south coast of New Zealand is associated with a positive value of the Antarctic Oscillation (AAO) (Thompson and Wallace 2000) and a stronger mid-latitude zonal circulation in the Southern Hemisphere. By August-October, when April-May values of this predictor are positive, La Niña conditions tend to be seen in the tropical Pacific, and there is also anomalous ridging seen over the southeastern United States. Anomalous ridging over the southeastern United States tends to enhance United States Gulf Coast landfall.

7.4 2006 Landfall Probabilities

Landfall probabilities for the 2006 season are calculated based upon values of the steering current predictors listed in the previous section and NTC. Landfall probabilities for the East Coast are quite high this year, due to a combination of predicted above-average NTC values and favorable steering currents for East Coast landfall. In general, a negative North Atlantic Oscillation (NAO) and Arctic Oscillation (AO) increases the likelihood of East Coast landfall, and both of these indices have been predominately negative so far this spring (Xie et al. 2005). Two of the three predictors utilized in our East Coast steering current model relate to the NAO and AO, especially Predictor 3, which as can be seen in Table 16, has very high values this year. The odds of a major hurricane making landfall along the East Coast are more than twice the climatological average value this year.

For the Gulf Coast, landfall probabilities are slightly below the climatological average. Steering current parameters for the Gulf Coast are mixed, with one of the predictors being slightly positive and the other predictor being moderately negative. However, it is to be noted that Gulf Coast landfall probabilities are still near their climatological averages (based on predicted high values of NTC), and therefore, coastal residents should prepare for a 26% probability of a landfalling major hurricane along the Gulf Coast.

Table 18 displays the landfall probabilities for the 2006 season.

Please visit our website at http://www.e-transit.org/hurricane for landfall probabilities for 11 U.S. coastal regions, 55 subregions and 205 coastal and near-coastal counties from Brownsville, Texas to Eastport, Maine.

Table 18: Estimated probability (expressed in percent) of one or more U.S. landfalling tropical storms (TS), category 1-2 hurricanes (HUR), category 3-4-5 hurricanes, and total hurricanes and named storms along the entire U.S. coastline, along the Gulf Coast (Regions 1-4), and along the Florida Peninsula and the East Coast (Regions 5-11) for 2006. The long-term mean annual probability of one or more landfalling systems during the 20th century is given in parentheses.

Coastal Region	TS	Category 1-2 HUR	Category 3-4-5 HUR	All HUR	Named Storms
Entire U.S. (Regions 1-11)	85% (80%)	67% (68%)	73% (52%)	91% (84%)	99% (97%)
Gulf Coast (Regions 1-4)	57% (59%)	33% (42%)	26% (30%)	51% (61%)	79% (83%)
Florida plus East Coast (Regions 5-11)	64% (51%)	47% (45%)	64% (31%)	81% (62%)	93% (81%)

8 Is Global Warming Responsible for the Large Upswing in 2004-2005 US Hurricane Landfalls?

8.1 Background

The U.S. landfall of major hurricanes Dennis, Katrina, Rita and Wilma in 2005 and the four Florida landfalling hurricanes of 2004 (Charley, Frances, Ivan and Jeanne) has raised questions about the possible role that global warming may be playing in these last two unusually destructive seasons.

The global warming arguments have been given much attention by many media references to recent papers claiming to show such a linkage. Despite the global warming of the sea surface of about 0.4°C that has taken place over the last two decades, global numbers of hurricanes and their intensity have not shown increases over the past twenty years (Klotzbach 2006). In addition, we have no valid physical theory as to why small changes of global average sea surface temperature (SST) should bring about increases in Atlantic basin hurricane activity. In the past century, Atlantic basin hurricane activity has been above-average both when global SST has been increasing (from the middle 1920s through the middle 1940s) and when global SST has been decreasing (from the middle 1940s through the middle 1960s).

The Atlantic has seen a very large increase in major hurricanes during the last 11-year period of 1995-2005 (average 4.0 per year) in comparison to the prior 25-year period of 1970-1994 (average 1.5 per year). This large increase in Atlantic major hurricanes is primarily a result of a multi-decadal increase in strength in the Atlantic Ocean thermohaline circulation (THC) which is not directly related to global temperature increase. Changes in ocean salinity are believed to be the driving mechanism. These multi-decadal changes have also been termed the Atlantic Multi-Decadal Oscillation (AMO). It should also be noted that during this same time period, activity in the Northeast Pacific basin has decreased considerably. When activity in these two basins (the North Atlantic and the Northeast Pacific) is summed together, there has been virtually no trend in major hurricanes.

There have been similar past periods (1940s-1950s) when the Atlantic was just as active as in recent years. For instance, when we compare Atlantic basin hurricane numbers of the last 15 years with an earlier 15-year period (1950-1964), we see little difference in hurricane frequency or intensity even though global surface temperatures were cooler and there was a general global cooling during 1950-1964 as compared with global warming during 1990-2004.

8.2 Discussion

There is no physical basis for assuming that global hurricane intensity or frequency is necessarily related to global mean surface temperature changes of less than $\pm$ 0.5°C. As the ocean surface warms, global upper air temperatures warm as well to maintain conditionally unstable lapse-rates and global rainfall rates at their climatological values. Seasonal and monthly variations of sea surface temperature (SST) within individual storm basins show only very low correlations with monthly, seasonal, and yearly variations of hurricane activity (Shapiro and Goldenberg 1998, Klotzbach 2006). Other factors such as tropospheric vertical wind shear, surface pressure, low level vorticity, mid-level moisture, etc. play more dominant roles in explaining hurricane variability than do surface temperatures. Although there has been a general global warming over the last 30 years and particularly over the last 10 years, the SST increases in the individual tropical cyclone basins have been smaller than the overall global warming (about half) and, according to the observations, have not brought about any significant increases in global major tropical cyclones except for the Atlantic which, as has been discussed, has multi-decadal oscillations driven primarily by changes in Atlantic salinity. No credible observational evidence is currently available that directly associates global surface temperature change with changes in global hurricane frequency and intensity.

Most Southeast coastal residents probably do not know how fortunate they had been in the prior 38-year period (1966-2003) leading up to 2004-2005 when there were only 17 major hurricanes (0.45/year) that crossed the U.S. coastline. In the prior 40-year period of 1926-1965, there were 36 major hurricanes (0.90/year or twice as many) that made U.S. landfall. It is understandable that coastal residents were not prepared for the great upsurge in landfalling major hurricanes in 2004-2005. For many years, we had been warning that the southeastern United States should expect great increases in hurricane-spawned destruction in future years.

We should interpret the last two years of unusually large numbers of U.S. landfalling hurricanes as natural but very low probability years. During 1966-2003, U.S. hurricane landfall numbers were substantially below the long-term average. In the last two seasons, they have been much above the long-term average. Although the 2004 and 2005 hurricane seasons have had an unusually high number of major landfall events, the overall Atlantic basin hurricane activity has not been much more active than five of the recent hurricane seasons since 1995 (e.g., 1995-1996, 1998-1999, 2003). What has made the 2004-2005 seasons so unusually destructive is the higher percentage of major hurricanes that moved over the U.S. coastline. These landfall events were not primarily a function of the overall Atlantic basin net major hurricane numbers, but rather of the favorable broad-scale Atlantic upper-air steering currents which were present the last two seasons. It was these favorable Atlantic steering currents which caused so many of the major hurricanes which formed to come ashore.

It is rare to have two consecutive years with such a strong simultaneous combination of high amounts of major hurricane activity together with especially favorable steering flow currents. The historical records and the laws of statistics indicate that the probability of seeing another two consecutive hurricane seasons like 2004-2005 is very low. Even though we expect to see the current active period of Atlantic major hurricane activity continue for another 15-20 years, it is statistically unlikely that the coming 2006 and 2007 hurricane seasons, or the seasons which follow, will have the number of U.S. landfalling major hurricane events that we have seen in 2004-2005.

9 Forecast Theory and Cautionary Note

Our forecasts are based on the premise that those global oceanic and atmospheric conditions which preceded comparatively active or inactive hurricane seasons in the past provide meaningful information about similar trends in future seasons. It is important that the reader appreciate that these seasonal forecasts are based on statistical schemes which, owing to their intrinsically probabilistic nature, will fail in some years. Moreover, these forecasts do not specifically predict where within the Atlantic basin these storms will strike. The probability of landfall for any one location along the coast is very low and reflects the fact that, in any one season, most U.S. coastal areas will not feel the effects of a hurricane no matter how active the individual season is. However, it must also be emphasized that a low landfall probability does not insure that hurricanes will not come ashore. Regardless of how active the 2006 hurricane season is, a finite probability always exists that one or more hurricanes may strike along the U.S. coastline or in the Caribbean and do much damage.

10 Forthcoming Updated Forecasts of 2006 Hurricane Activity

We will be issuing seasonal updates of our 2006 Atlantic basin hurricane forecasts on **Friday 1 September** and **Tuesday 3 October 2006**. The 1 September and 3 October forecasts will include separate forecasts and updates of September-only and October-only Atlantic basin tropical cyclone activity. A verification and discussion of all 2006 forecasts will be issued in late November 2006. Table 19 displays our forecast schedule for the remainder of the 2006 hurricane season. Our first seasonal hurricane forecast for the 2007 hurricane season will be issued in early December 2006. All of these forecasts will be made available on the web at: http://hurricane.atmos.colostate.edu/Forecasts.

Table 19: Timetable of upcoming forecasts and updates for the 2006 hurricane season.

Forecast Date	Based on Data Through	Upcoming Forecasts and Updates			
1 September 2006	August 2006	August Verification	Updated September Forecast	Updated October Forecast	Updated Seasonal Forecast
3 October 2006	September 2006		September Verification	Updated October Forecast	Updated Seasonal Forecast
Late November 2006	Verification of all Forecasts				

11 Acknowledgments

Besides the individuals named on page 4, there have been a number of other meteorologists that have furnished us with data and given valuable assessments of the current state of global atmospheric and oceanic conditions. These include Brian McNoldy, Arthur Douglas, Richard Larsen, Todd Kimberlain, Ray Zehr, and Mark DeMaria. In addition, Barbara Brumit and Amie Hedstrom have provided excellent manuscript, graphical and data analysis and assistance over a number of years. We have profited over the years from many in-depth discussions with most of the current and past

NHC hurricane forecasters. The second author would further like to acknowledge the encouragement he has received for this type of forecasting research application from Neil Frank, Robert Sheets, Robert Burpee, Jerry Jarrell, former directors of the National Hurricane Center (NHC), and from the current director, Max Mayfield and their forecast staffs. Uma Shama and Larry Harman of Bridgewater State College, MA have provided assistance and technical support in the development of the Landfalling Hurricane Probability Webpage. We also thank Bill Bailey of the Insurance Information Institute for his sage advice and encouragement.

The financial backing for the issuing and verification of these forecasts has in part been supported by the National Science Foundation and by the Research Foundation of Lexington Insurance Company (a member of the American International Group). We also thank the GeoGraphics Laboratory at Bridgewater State College for their assistance in developing the Landfalling Hurricane Probability Webpage.

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13 Verification of Previous Forecasts

Table 20: Summary verification of the authors' six previous years of seasonal forecasts for Atlantic TC activity between 2000-2005.

2000	8 Dec. 1999	Update 7 April	Update 7 June	Update 4 August	Obs.
No. of Hurricanes	7	7	8	7	8
No. of Named Storms	11	11	12	11	14
No. of Hurricane Days	25	25	35	30	32
No. of Named Storm Days	55	55	65	55	66
Hurr. Destruction Potential	85	85	100	90	85
Intense Hurricanes	3	3	4	3	3
Intense Hurricane Days	6	6	8	6	5.25
Net Tropical Cyclone Activity	125	125	160	130	134

2001	7 Dec. 2000	Update 6 April	Update 7 June	Update 7 August	Obs.
No. of Hurricanes	5	6	7	7	9
No. of Named Storms	9	10	12	12	15
No. of Hurricane Days	20	25	30	30	27
No. of Named Storm Days	45	50	60	60	63
Hurr. Destruction Potential	65	65	75	75	71
Intense Hurricanes	2	2	3	3	4
Intense Hurricane Days	4	4	5	5	5
Net Tropical Cyclone Activity	90	100	120	120	142

2002	7 Dec. 2001	Update 5 April	Update 31 May	Update 7 August	Update 2 Sept.	Obs.
No. of Hurricanes	8	7	6	4	3	4
No. of Named Storms	13	12	11	9	8	12
No. of Hurricane Days	35	30	25	12	10	11
No. of Named Storm Days	70	65	55	35	25	54
Hurr. Destruction Potential	90	85	75	35	25	31
Intense Hurricanes	4	3	2	1	1	2
Intense Hurricane Days	7	6	5	2	2	2.5
Net Tropical Cyclone Activity	140	125	100	60	45	80

2003	6 Dec. 2002	Update 4 April	Update 30 May	Update 6 August	Update 3 Sept.	Update 2 Oct.	Obs.
No. of Hurricanes	8	8	8	8	7	8	7
No. of Named Storms	12	12	14	14	14	14	14
No. of Hurricane Days	35	35	35	25	25	35	32
No. of Named Storm Days	65	65	70	60	55	70	71
Hurr. Destruction Potential	100	100	100	80	80	125	129
Intense Hurricanes	3	3	3	3	3	2	3
Intense Hurricane Days	8	8	8	5	9	15	17
Net Tropical Cyclone Activity	140	140	145	120	130	155	173

2004	5 Dec. 2003	Update 2 April	Update 28 May	Update 6 August	Update 3 Sept.	Update 1 Oct.	Obs.
No. of Hurricanes	7	8	8	7	8	9	9
No. of Named Storms	13	14	14	13	16	15	14
No. of Hurricane Days	30	35	35	30	40	52	46
No. of Named Storm Days	55	60	60	55	70	96	90
Intense Hurricanes	3	3	3	3	5	6	6
Intense Hurricane Days	6	8	8	6	15	23	22
Net Tropical Cyclone Activity	125	145	145	125	185	240	229

2005	3 Dec. 2004	Update 1 April	Update 31 May	Update 5 August	Update 2 Sept.	Update 3 Oct.	Obs.
No. of Hurricanes	6	7	8	10	10	11	15
No. of Named Storms	11	13	15	20	20	20	27
No. of Hurricane Days	25	35	45	55	45	40	51
No. of Named Storm Days	55	65	75	95	95	100	125
Intense Hurricanes	3	3	4	6	6	6	7
Intense Hurricane Days	6	7	11	18	15	13	16.75
Net Tropical Cyclone Activity	115	135	170	235	220	215	275